## 5.4 Project Finance Models, Analytical Techniques for Evaluating MPPs

This section describes analytical models that can be used to underwrite loans and determine the credit spread for merchant power plant transactions from the perspective of the ADB. There are two general types of models used to evaluate MPP risks -- project finance models and forward price simulation models:

1) Project finance models measure value and credit risk from an investor perspective -- including debt investors, equity investors and investment by multilateral agencies such as the ADB.

2) Forward price simulation models measure future electricity prices, price volatility and the impacts of alternative market frameworks on customers and investors. The price forecasts in these models are inputs to project finance models of merchant power plants. Forward price simulation models also can be used to quantify impacts of policy issues through measuring total cost to customers, prices faced by customers, incentives for developers to make investments, system reliability, price volatility and other factors. These subjects are addressed in section 5.7.

The remainder of this section describes how project finance models and forward price simulation models can be used to quantify risks of merchant power plants. Application of the project finance models to MPPs includes use of models to determine break-even prices and sensitivity; definition and measurement of electricity price volatility; use of Monte Carlo simulation in measuring risks associated with merchant power plants. The discussion of forward price simulation models considers long-run marginal cost analysis and complex simulation analysis that incorporates the behaviour of MPP developers.

### 5.4.1 Project Finance Models

A basic tool for risk analysis of merchant plants is a model of how cash flows are affected by market risk. Project finance models used in measuring risks associated with merchant power plants below have equations for optimizing debt capacity, measuring chances of going bankrupt, and calculating the electricity price that would be required in bilateral contracts (the software is included on the attached compact disk). Outputs from a project finance model include the internal rate of return on the equity investment and the internal rate of return on aggregate project free cash flow, debt service coverage ratios and the amount of debt that cannot be re-paid at the end of the life of a project.

The following statement made by Fitch Investor Services describes how project finance models are the centrepiece of assessing the credit quality of merchant power plants:

> Models of projected cash flow are a very significant component in the credit evaluation of merchant plant transactions. In a merchant power project, cash flow forecasting is based on a model [that is] a reasonably accurate representation of the project's expected operating performance and operating expenses at varying levels of output over the life of the debt. The model also incorporates the terms of the financial structure, debt amortization, and interest payments… Fitch reviews the base case and various stress scenarios affecting project cash flows. Typical cases include lower market prices than the base

case, higher operating costs, lower gas prices, unscheduled outages, or changes in environmental regulation.

Project finance models have long been used by the ADB and others to evaluate many investments including electricity plants with long-term purchase contracts. The project finance models used in evaluating merchant power risk must be able to measure the effects of price volatility; merchant plant debt enhancements such as cash flow sweeps and cash flow traps; debt service reserves; risk mitigation from bilateral contracts; subordinated debt structures; risk absorption by fuel suppliers and other characteristics associated with merchant plants.

To illustrate how project finance models are used in the context of evaluating a merchant plant and how this contrasts from plants with long-term PPA contracts we summarize selected issues discussed later on in the report. The table below shows how a cash flow trap covenant, a cash flow sweep covenant, alternative leverage, and a bilateral contract can moderate the risks associated with a merchant plant. A full description of these issues sweeps in the context of ADB's underwriting process for the debt of an MPP is described in Sections 5.5 and 5.6. We summarise the analysis here to show the unique way in which project finance models are used together with price volatility, simulation and credit analysis in the underwriting of MPP transactions. The table below demonstrates the financial structure of an MPP can have an important effect on the probability of default that the plant will not be able to pay off debt and the required pricing of MPP debt issued by the ADB or other lenders. In a case without structural enhancements -- cash sweeps, cash traps and a debt service reserve -- the probability of default for the NGCC plant is 4.67% assuming electricity price volatility of 25% and 14.64% assuming a very high price volatility of 14.74%. If a cash flow trap and cash flow sweep covenants are included in the transaction tied to the debt service coverage ratio, the credit spread falls to 2.93%. If a bilateral contract is used to mitigate risks associated with price volatility, the required pricing falls to 2.19%. The process for measuring MPP risks and structuring MPP debt to mitigate the risks is explained in the remainder of the report.

| | NGCC MPP Plant | | | | | | |
|---|---|---|---|---|---|---|---|
| | Without Enhancements | Higher Price Volatility | Lower Debt Leverage | With 2.0x Cash Flow Trap | With 3.0x Cash Flow Sweep | With Cash Flow Sweep and Cash Flow Trap | 5-year Bilateral Contract for 50% of Output |
| **Results** | | | | | | | |
| **Credit Pricing** | | | | | | | |
| Probability of Default | 31.30% | 49.40% | 27.90% | 19.10% | 5.00% | 4.10% | 4.00% |
| Loss, Given Default | 14.91% | 29.83% | 11.05% | 22.75% | 68.82% | 71.44% | 54.87% |
| *Required Credit Spread* | *4.67%* | *14.74%* | *3.08%* | *4.35%* | *3.44%* | *2.93%* | *2.19%* |
| **DSCR** | | | | | | | |
| Average DSCR | 1.82 | 1.82 | 2.19 | 1.82 | 1.82 | 1.82 | 1.66 |
| Minimum DSCR | 1.45 | 1.45 | 1.76 | 1.45 | 1.45 | 1.45 | 1.45 |
| **Returns** | | | | | | | |
| Project IRR | 14.78% | 14.78% | 13.64% | 14.78% | 14.78% | 14.78% | 11.35% |
| Equity IRR | 11.09% | 11.09% | 11.09% | 11.09% | 11.09% | 11.09% | 9.50% |
| | | | | | | | |
| **Assumptions** | | | | | | | |
| **Electricity Price** | | | | | | | |
| Price Volatility | 25% | 35% | 25% | 25% | 25% | 25% | 25% |
| Price Trend | -1% | -1% | -1% | -1% | -1% | -1% | -1% |
| **Debt Characteristics** | | | | | | | |
| Leverage | 60% | 60% | 50% | 60% | 60% | 60% | 60% |
| | | | | | | | |
| **Bilateral Contract** | | | | | | | |
| Term | - | - | - | - | - | - | 10 |
| Price | - | - | - | - | - | - | 35 |

The table illustrates the type of analysis that is required for assessing the risk of an MPP – volatility and trends in electricity prices must be established; probability of loss and loss, given default should be assessed; alternative structural enhancements

should be measured; debt service reserves must be taken into account. The risks can then be translated into DSCR benchmarks and debt leverage ratio benchmarks for different types of plants.

### 5.4.2 Break-even Analysis, Scenario Analysis and Sensitivity Analysis

The next sections describe project finance models can be applied in assessing the risk of a merchant power plant. This section discusses traditional approaches to assess risk that are derived from using expert judgement on economic variables such as the electricity price. The next section introduces mathematical techniques that incorporate the price volatility of electricity and apply Monte Carlo simulation to project finance models.

Traditional methods of using a project finance model with expert judgement to assess the risk of an MPP include break-even analysis, scenario analysis and sensitivity analysis:

- ✓ Sensitivity analysis evaluates how the credit quality and value of an MPP is affected by changing single variables.
- ✓ Scenario analysis measures the ability of an MPP to service debt and generate cash flow under a set of assumptions for market prices, fuel costs, plant availability and other variables.
- ✓ Break-even analysis tests how much worse a variable can become before a default or non-payment of debt occurs. Break-even analysis can be applied to the minimum debt service coverage ratio or the amount of debt outstanding at the end of the life of a project.

The following quotes from bond rating agencies Fitch and Moody's illustrate how the use of sensitivity analysis, scenario analysis and break-even analysis is applied in the underwriting of merchant power plant transactions:

**Fitch**

> The object is to determine if the project is likely to continue to cover operating expenses and debt interest and principal payments despite unexpected stress levels. The scenarios also reveal whether there are particular variables to which the project has a greater degree of sensitivity. The evaluation of the stress scenario results is focused on the ***minimum debt service coverage*** in any single year and the average debt service coverage over the entire life of the debt. If the cash flows are unable to cover payments on project debt under certain stress scenarios, the debt service reserve or other forms of credit enhancement available to the project are applied. Thus, [sensitivity analysis] can be used to size the appropriate debt service reserve or other credit enhancements needed to avoid default under adverse scenarios. Fitch performs sensitivity analyses that stress cash flows down to a break-even level to see how the project performs under extreme hardship conditions and at what minimum power price the project can perform while covering operating costs and debt service payments.

**Moody's**

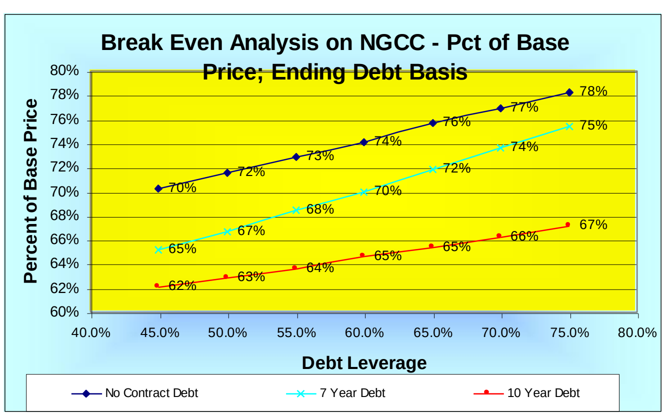
Moody's believes that the appropriate analytical beginning is to determine a credible market forecast and to assess the projects break-even position relative to that market forecast. A break-even point substantially below the market forecast allows a project to absorb unexpected market fluctuations in prices and volumes which is essential to an investment grade debt security. From this analysis, one can derive the appropriate capital structure for each project individually.

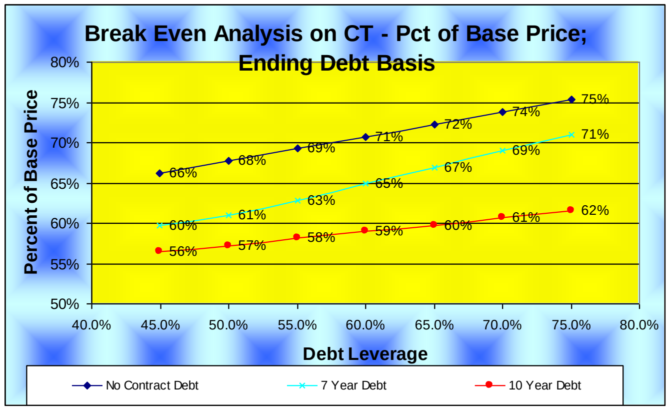
Moody's believes that a merchant plant will be subject to swings in prices as power markets develop. The better able a project is to absorb changes in prices (and changes in volumes) the higher its rating will be. Our belief is that an investment-grade-rated merchant power plant will have a break-even point, where it fully covers its debt service obligations, between 30% and 50% below ***a reasonable market forecast price***. The amount of the discount is determined by the characteristics of the market and the reasonableness of the market forecast assumptions.

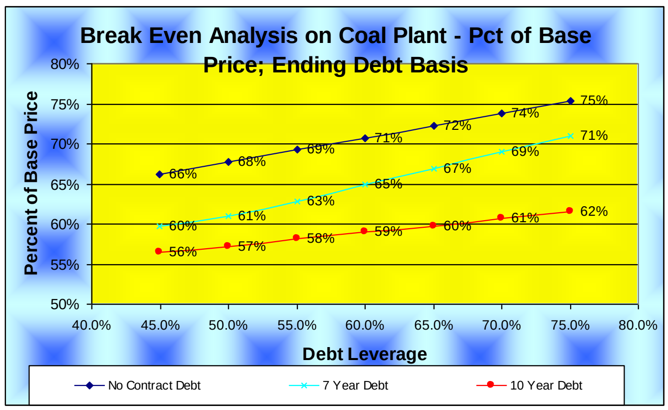
**Standard & Poor's**

Where projects elect to obtain key supply inputs from spot markets, the risk of cash flow erosion may raise project credit concerns, particularly in volatile markets, such as energy and other commodities. Stronger projects will be those that can ***demonstrate a resilience to worst case cost movement scenarios as indicated by historical trends***. Historical price trends in such commodities as crude oil, petrochemical products, metals and pulp and paper can provide a basis for analysis of potential worst case price movements. Standard & Poor's will rely in part on financial scenario analysis to assess the effects of supply and cost disruptions on project economics.

Break-even analysis is applied in a later part of the report (Section 5.6) to demonstrate how bilateral contracts affect risks faced by merchant plants. The graphs below illustrate application of the break-even electricity price for three different bilateral contract cases applied to the three plant types. In one case, no bilateral contract is assumed; in a second case, a bilateral contract that covers half of the plant output for six years is assumed; and, in a third case a ten year bilateral contract that covers the entire output of the plant is assumed. Data in the graph show the percent reduction in the spot market price on non-contracted electricity generation while assuring that various sized loans can just be paid from cash flow of the project by the end of its lifetime assuming various different levels of debt leverage.






These break-even charts demonstrates that if the ADB is to make investments in merchant plants, an outlook is required for the future price level as well as the uncertainty associated with the price level. In each case, the margin in acceptable price reduction is far greater with bilateral contracts than without bilateral contracts. Differential break-even prices driven by bilateral contracts are highest in the cases where the debt leverage is high. The percent reduction in prices that can be accepted is analogous to the volatility concepts described below. If the ADB is comfortable that the spot price will be above the break-even levels, the credit will more likely be acceptable. The break-even analysis where prices are lowered until the merchant plant cannot cover debt at the end of its project life is the building block for probability analysis which measures the loss given default on a loan. Cases where the loan cannot be repaid define a probability of loss.

### 5.4.3 Long-run Volatility of Electricity Prices

In reading virtually any investment analyst report on merchant power plants a persistent theme involves the risk resulting from volatility of market prices. For example, a report written by Moody's on MPPs stated: "The recurring theme of merchant power risk is increased uncertainty and increased ***volatility***. Nowhere in the analysis is this phenomenon more evident than in the projection of the future price of power in a given market." Similarly, Standard and Poor's discusses volatility in comparing a merchant plant with a plant that has a long term power contract: "Overall, the rating of a merchant plant will be lower than that of a traditional single-

asset IPP with the same capital structure and cash flow coverage of interest because of the greater ***volatility*** and uncertainty of its cash flows in an open market."

The following statement describes how the volatility of electricity is very high compared to other commodities because of the lack of the ability to store electricity:

> "Electricity is by Far the Most Volatile of Commodities: Recent crude oil prices have seen price fluctuations as high as 70 percent. The volatility of coal spot prices over the past year in Europe has averaged 20 percent. Nickel, the most volatile metal traded, has seen volatility of 60 percent, and over the past five years, the price of natural gas futures has varied by 100 percent. However, none of these volatility figures compare to power prices this year in Europe. This January on the Amsterdam Power Exchange, the price of electricity suddenly jumped from 44 euros/MWh to 474 euros/MWh - a volatility of about 1,500 percent. The biggest factor at play in power markets is supply and demand. But because consumers don't know, in real time, how much electricity they are using, they can't react to high prices by cutting their consumption. Wholesale power markets, during periodic supply/demand crunches, have exhibited volatility 20 to 30 times that seen in financial and oil markets. This is driven by the fact that power cannot be truly stored."

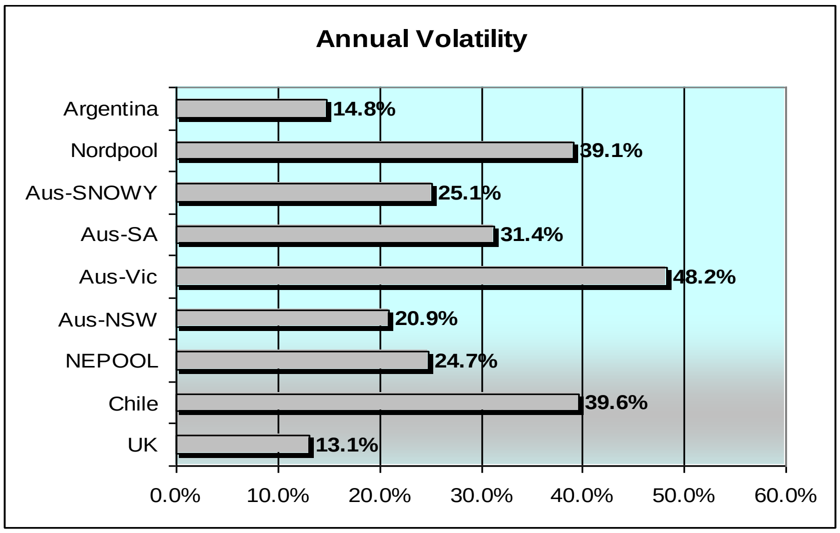
In using project finance models to evaluate IPP projects with long-term contracts, financial professionals did not need to consider statistical measures such as volatility, value at risk and risk hedging analysis. The focus in traditional project finance models was generally on judgmental considerations of business risk related to plant breakdowns, contracts not being honoured and other risks that are not subject to mathematical analysis using historic data. In the case of merchant power plants, notions of hedging forward price movements, assessing the standard deviation in price estimates and time series analysis of market prices is becoming more prevalent than judgemental assessments.

As shown above, the term volatility is universally discussed in describing potential movements in electricity prices, variations in the cash flow of merchant plants and fluctuations in fuel prices. Often, however, volatility is used in describing the general risk of a project rather than as a mathematical statistic that explicitly measures risk. Technically, volatility is a number summarises the potential range in price movement. From a statistical perspective, volatility of prices and cash flow is the building block of measuring credit risk and the value of merchant power plants. Volatility of cash flow determines the probability of bankruptcy or default; price volatility drives the value of options associated with the dispatch of plants; price volatility is the reason for hedging risks through long-term contracts; and price volatility is a central component in measuring the cost of capital.

Intuitively, volatility can be thought of as the variability (standard deviation) of the percent change in prices (stock prices, oil prices, natural gas prices, electricity prices or cash flows from a merchant plant.) If volatility is used in a mathematical equation that represents prices, then one can determine how likely the price will be above or below a certain level at a future point in time. Since volatility is related to variation in the percent change rather than the absolute level of prices, the unit of volatility is percentage (rather than dollars, index values, bond prices or other units.) Volatility measures the likelihood that prices will move by a certain percentage due to the random shocks over a certain period of time. For example, if the volatility of electricity prices is 20% (and the percent change in price follows a normal distribution

without mean reversion), then there is a 67% chance that a random movements in prices over the next year will result a price that is within 20% of the current price. Similarly, there is a 33% chance that the next year price level will be more than 20% higher or lower than the current price. Mathematical equations for volatility are described in Appendix 3.

Volatility can be computed for annual, monthly, daily or hourly prices. In the credit analysis of MPPs, annual volatility is most important. Due to the fact that electricity cannot be stored, short-term volatility of prices that cause cash flows to increase or decrease in certain hours, days or months are less important than long-term price movements. Annual price volatility in various markets around the world is shown in the graph below. Mathematical techniques used in making the volatility calculations are described in Appendix 3. The source of raw data is discussed in Part 3 of the MPP report. Annual price volatility is highest for the Victoria state in Australia, Nordpool and Chile and is lowest for Argentina and the UK. High volatility is driven by hydro variability and changes in supply while low volatility is characterised by markets with surplus capacity.




To illustrate the importance of volatility parameters in analysis of investment decisions, the table below shows how different levels of annual volatility in the price of electricity affect the probability that a project finance loan will default. We include this table before fully explaining the process to compute probability of default to show the practical way in which volatility affects decision making. The table shows that if the annual volatility of electricity prices is 25% the probability that a loan on an NGCC plant will not be paid back to banks (the probability of default) is 32%, while if the annual volatility is 35%, then the probability of not being paid is 49% and if the annual volatility is 15%, the probability of default is 11%. Much of the remainder of the report describes how the probability of not being paid can be influenced by signing long-term contracts, using forward markets to lock in prices, negotiating flexible supply contracts, incorporating financial covenants in loan agreements, changing the debt leverage of the plant, using mezzanine and subordinated financing and purchasing insurance.

The table illustrates that the probability of default is lower for a capital intensive coal plant than a fuel intensive NGCC plant because the coal plant has a larger capital base and therefore can accept a larger decline in prices before a default occurs. If

the price of fuel varies with the price of electricity, the probability of loss declines. Much of the remainder of the report focuses on NGCC plant to highlight the effects of volatility on the underwriting of MPP credit.

| | Coal Plant | | | NGCC | | |
|---|---|---|---|---|---|---|
| | Base Price Volatility | High Price Volatility | Low Price Volatility | Base Price Volatility | High Price Volatility | Low Price Volatility |
| **Results** | | | | | | |
| Credit Pricing | | | | | | |
| Probability of Default | 12.10% | 30.00% | 0.90% | 31.80% | 49.40% | 10.80% |
| Loss, Given Default | 2.30% | 2.30% | 1.16% | 11.54% | 19.30% | 3.93% |
| Required Credit Spread | 0.28% | 1.54% | 0.010% | 3.67% | 9.53% | 0.425% |
| **Assumptions** | | | | | | |
| Electricity Price | | | | | | |
| Price Volatility | 15% | 25% | 35% | 15% | 25% | 35% |
| Price Trend | -1% | -1% | -1% | -1% | -1% | -1% |
| Debt Characteristics | | | | | | |
| Leverage | 60% | 60% | 60% | 60% | 60% | 60% |
| Term of Debt | 15 | 15 | 15 | 15 | 15 | 15 |

### 5.4.4 Monte Carlo Simulation in Analysis of MPPs

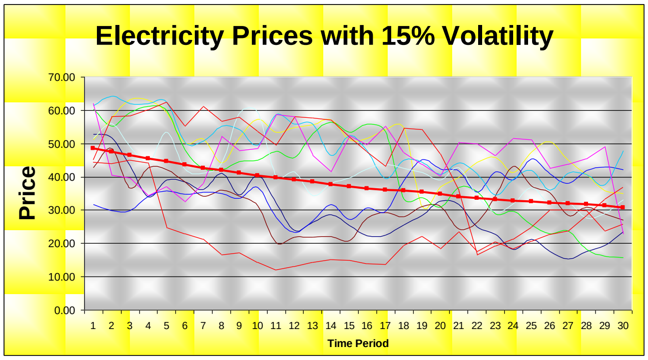
Once volatility is computed, a method must be developed that translates volatility into measurement of risk. A common way to apply volatility in measuring the risk associated with cash flow is to use a process known as Monte Carlo simulation. Monte Carlo simulation can be applied to measure the probability that a loan will not be repaid and it can also quantify the deviation in free cash flow. The above tables that present the probability of default using different debt structures and different volatility assumptions were developed using Monte Carlo simulation. The fact that Monte Carlo simulation is used in practice to evaluate merchant power plants is discussed in the following quote by Paul Ashley, a project finance expert:

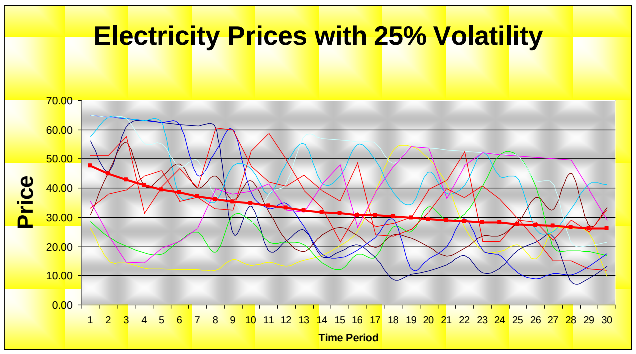
> "Given plausible assumptions for key risk drivers (for example, volatility of gas prices), the ratings are then built around simulating cash flows and debt coverage for individual projects. These simulations can then determine probability and loss distribution and directly observe the impact on cash flows and riskiness of a particular transaction structure under different market environments.
>
> The parameterization of the rating simulations combines market data and expert judgment in a structured way that allows transparency and consistency in risk evaluation without losing the ability to capture the specifics of a transaction structure."

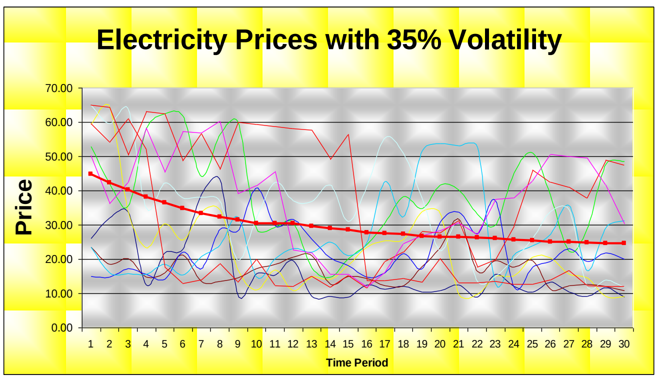
Monte Carlo simulation uses random numbers and a mathematical process to construct a range of possible prices over different time periods. The way in which random draws affect prices depends on the volatility parameter – the higher the volatility the more the potential variation in prices. Technical details that describe how Monte Carlo simulation can be applied in practice are described in Appendix 1.

To illustrate how the Monte Carlo simulation process works, three graphs are presented below that show selected price patterns that are generated by assuming an annual volatility of 15%, 25% and volatility of 35%. The 15% volatility assumption roughly corresponds to markets in Argentina, the UK and the US while the higher volatility parameter corresponds to markets in Scandinavia, Chile and parts of Australia. Each graph presents ten different price paths generated by random numbers.

The simulation process in actual risk assessment of MPPs described below in Section 5.4 and 5.5 uses thousands of simulations. These price simulations are then input into the project finance model to determine the probability that various outputs in the model will occur. The simulations also include assumptions with respect to time trends, lower and upper boundaries and an assumption for mean reversion – the speed at which prices move back to equilibrium levels.




### 5.4.5 Long-run Price Trends and MPP Risk Analysis

The analysis of volatility seems to suggest that markets in the UK and Argentina had relatively low risk. However as discussed in Part 3, MPPs in these two markets have experienced severe financial distress because of the decline in market prices. The prices have did not vary by a great deal from year to year, but they experienced a protracted downward trend. Experiences in these markets demonstrate that the assessment of MPP risk must include evaluation of the trends in prices as well as the

volatility of prices. In other words, the long-term trends in prices affect the financial risk more than the volatility of prices. The next two sections discuss how the ADB can make estimates of the long-term trend in prices using marginal cost analysis and forward price simulation.

To develop forward price trends, outlooks must be established for energy prices, capacity prices, and capacity expansion. The price outlooks are required for both the individual investment analysis and for the country strategic plans. For the individual MPP transactions, the ADB must evaluate whether long-term prices can support plant investments. For the country strategic plans, the ADB must consider how policy options affect long-term energy and capacity prices. In describing the process of making long-term projections, we first discuss long-term marginal cost analyses and then forward pricing simulation models derived from forecasts of supply and demand.

Requirements to forecast electricity prices in assessing the credit risk of an investment are described in the following statement made by Moody's:

> In a deregulated market, electricity will trade and be priced as a commodity and generating plants will face changes in volumes and prices which will result in boom and bust cycles. Market participants will react to these cycles with decisions to expand or contract capacity, which will fuel more cycles. Managers will be forced to forecast demand and will face the repercussions of both over-forecasting, as excess capacity will lower prices and returns, and under-forecasting, as a capacity shortage will invite new competitors and/or re-regulation. And competitors will exploit poor management decisions in a way that was impossible in a regulated environment.

Price outlooks used to evaluate individual transactions and used in quantifying policy frameworks are often developed from complex simulation models that rely on large databases. A mistake made in the relatively short history of merchant power has been to rely on the complex models without questioning the general plausibility of the results and establishing a reference point for the projections. To avoid repeating this mistake in projecting price trends, the ADB should compute long-run marginal costs as a reference point in developing more complex forecasts. Therefore, before describing forward models, we discuss how long-run marginal cost can be calculated to provide the ADB with a tool to evaluate the general plausibility of complex model results. The following two statements by Moody's illustrate the need for a reference point in making electricity price forecasts:

> In Moody's opinion, ***project economics associated with long-term power market forecasts should be viewed sceptically***. Over the short- to-intermediate term, the introduction of new generating technology into today's electrical grids will almost invariably provide project owners with an opportunity for exceptional risk-adjusted rates of return. But over the longer term, new entrants, which offer similar — or perhaps better — technology, will inevitably drive market prices down, potentially undermining the economic rationale of even what would now appear to be the most favourably positioned projects. What's more, the long-term prediction of power prices — and thus a specific project's ability to retain or add customers — is heavily dependent upon inherently uncertain assumptions regarding a particular market's demand and supply characteristics; regulatory and political environments; and the economic rationale of new investors.
>
> It is important to emphasize that the power rate consultants' computer models

generally employ linear programming techniques and are extremely complicated. By the time Moody's issues a rating, Moody's will understand in great detail the power rate consultant's assumptions and approach. However, Moody's cannot know the computer model's detailed logic. Thus, ***there is a black box character to these models.***

### 5.4.6 Long-run Marginal Cost and Forward Price Projection

A starting point in analysis of electricity trends is computation of the long-term marginal cost. Long-term marginal cost is a conceptual tool that explains why prices should converge to certain levels and should be part of the underwriting process for an MPP. An understanding of the marginal cost of electricity is essential to analysis of the forward pricing and plant valuation in any industry. Assumption that prices will indefinitely be below or above marginal cost by a wide margin is not reasonable without assuming barriers to entry or market intervention that should not be sustainable. Credit analysis for MPPs should therefore compare long-run marginal cost with long-term price forecasts to assess whether the forecasts are reasonable. In addition, development of long-run marginal cost analysis is a useful tool in many other aspects of the analysis of market frameworks. For example, long-run cost analysis can be used to assess whether retail rates are set at levels that provide an appropriate consumption incentive; whether significant market power is present; and, whether prices established in long-term contracts are reasonable.

In evaluating investments and policy with respect to merchant plants, the ADB should have a tool that evaluates the long-run marginal cost of electricity. A misunderstanding of long-run marginal costs has caused problems in the underwriting of MPPs. For example, price forecasts in Argentina assumed that an inefficient capacity mix would remain in place, neglecting the downward trend toward the long-run cost defined by more efficient capacity. Long-run marginal cost is important because at some point rational economic behaviour must exist. This point is made by Peter Rigby of Standard and Poor's:

> Generally most models assume rational behaviour by market participants, and that a system will operate economically in the most efficient manner, given the physical constraints of the system. Unfortunately, market participants do not always behave rationally or uniformly – fortunately they do not behave recklessly either…Underlying every model is the assumption that the markets will operate in a perfect long-term equilibrium, and that they will price electricity at the marginal cost of production. Unfortunately the reality of energy markets appears much different. Equilibrium lasts momentarily at best. A sudden change in fuel prices, a change in system load, or the presence of a new power station will upset the equilibrium.

A model for determining long-run marginal cost for purposes of evaluating merchant plants is presented in Appendix 3. This model combines the tools discussed above – carrying charge rates from the project finance model, plant costs from the case study discussion and a load duration curve for the Philippines. We have included the long-run marginal cost model as part of the tool-kit for evaluating merchant power plants because, although it is simple, long-run marginal cost can be an effective tool in assessing whether complicated forward pricing models with multi-regional transmission constraints, volatility premiums, price spikes and Monte Carlo simulation of plant outages are producing reasonable results. The long-run marginal cost in

evaluating price forecasts described in Appendix 3 begins with analysis of prices in current markets. Next, long-run marginal cost is computed from load profiles and cost characteristics of new plants. Prices derived from long-run marginal cost are high enough to promote construction of an efficient mix of new plants. Finally, with current prices and equilibrium prices established, evaluation of merchant plants using this framework must address how and when prices will move from current market levels to equilibrium.

Long-run marginal costs can be used to evaluate the likely direction of future prices. If current prices are higher than the price level that covers the cost of building new capacity, you would expect the prices to come down. This situation is illustrated by the case of Argentina and the Northeast US, where price levels at the inception of the market were above the prices required for construction of new combined cycle plants. On the other hand, if current price levels do not allow profitable construction of new plants, you should expect prices to increase.

### *Example of Using Long-Run Marginal Cost to Evaluate Price Forecasts in MPP Proposals*

In thinking about the forward price model presented below suppose an ADB analyst must review a forecast of electricity market prices made by a market price consultant for a plant in Vietnam. The ADB staff must review the forward price forecast without a fancy hour-by-hour "multi-regional" simulation model. In reviewing the market price forecast, a place to start is evaluation of the level of current prices. Next, the level of prices at "equilibrium" could be computed where the price just covers the cost of constructing and operating new capacity and where an optimal mix of resources exists in the market. Finally, an assessment could be made about how prices will move from current levels to long-run marginal cost that defines equilibrium levels. While this simple approach may not address specific plant outages, variability in price spikes, changes in hydro conditions profitability of individual existing plants or generating unit ramp rates, the simple framework includes evaluation of actual prices, how fuel prices and changes in productivity that affect long-term prices, and behavior of merchants that affect how prices will move to equilibrium.

The marginal cost framework can be used to evaluate the effects of the level of capacity and/or the mix of generating plants in a country not being at an equilibrium level. In cases where there is too much capacity, too little capacity, or the wrong mix of capacity, prices will not be at equilibrium levels and private developers can potentially profit from realizing prices that do not reflect the cost of new building plants. For example, if there is too much peaking capacity in a region relative to the economic optimum, the net cost of capacity for base load plants – after recovery of variable costs from off-peak prices -- is less than the annualized cost of a peaking plant.

The two tables below shows the computation of long-run marginal costs in various scenarios. The first table demonstrates prices that result from computation of marginal cost if the market is in equilibrium and the carrying charges are derived from debt leverage of 60%. At a load factor of 62%, representing the average load factor of the system, the long-run marginal cost using the three representative plants is \$38/MWH. (This long-run marginal does not include an assumption of a declining price trend. With a declining price trend, the long-run marginal cost is consistent with the \$45/MWH assumption used in the project finance model.) The table illustrates that different plants face different prices because of the time at which dispatch occurs. If a plant operates at 100% load factor, the price faced by the plant is \$34/MWH instead of \$38/MWH.

The second table shows the effect of different carrying charges and technology assumptions on the long-run marginal cost. With higher carrying charges, the long-run equilibrium price increases because prices must cover higher costs of capital. If the

carrying charge increases because of lower leverage, the mix of capacity and the long-run marginal cost increase from $38.81/MWH to $45.50/MWH – an increase of 17%. In addition, the capacity mix changes and low capital cost unit peaking plants are a far higher proportion of the total capacity.

**Long-Run Marginal Cost in Equilibrium - Base Carrying Charges**

| | | | | |
|---|---|---|---|---|
| Average On-Peak Interruptible Energy Cost | $ 30.00 | per MWH | All-in Price at Capacity Factor of 100.0% | $ 34.00 per MWH |
| Average Off-Peak Interruptible Energy Cost | $ 23.56 | per MWH | All-in Price at Capacity Factor of 62.00% | $ 38.81 per MWH |
| Average All Hours Interruptible Energy Cost | $ 26.76 | per MWH | All-in Price at Capacity Factor of 50.00% | $ 42.34 per MWH |
| Average All Hours Interruptible Energy Cost | $ 30.00 | per kW/Year | All-in Price at Capacity Factor of 25.00% | $ 58.97 per MWH |
| Capacity Price | $ 63.44 | | | |

| | Capacity Percent | Energy Val per kW | Capacity Cost/kW | Net Capacity Value/kW | Capacity Value Deviation | Capacity Factor |
|---|---|---|---|---|---|---|
| Peakers | 48.73% | $ - | $ 63.44 | $ 63.44 | $ 0.00 | 20.70% |
| Combined Cycle | 9.07% | $ 52.39 | $ 115.75 | $ 63.36 | $ 0.00 | 74.65% |
| Coal | 42.20% | $ 136.10 | $ 199.46 | $ 63.35 | $ 0.00 | 89.62% |
| Average | | | | $ 63.38 | $ 0.00 | |
| Reserve Margin | 15.00% | | | | | |

**Long-Run Marginal Cost in Equilibrium - High Carrying Charges**

| | | | | |
|---|---|---|---|---|
| Average On-Peak Interruptible Energy Cost | $ 30.00 | per MWH | All-in Price at Capacity Factor of 100.0% | $ 39.61 per MWH |
| Average Off-Peak Interruptible Energy Cost | $ 30.00 | per MWH | All-in Price at Capacity Factor of 62.00% | $ 45.50 per MWH |
| Average All Hours Interruptible Energy Cost | $ 30.00 | per MWH | All-in Price at Capacity Factor of 50.00% | $ 49.22 per MWH |
| Average All Hours Interruptible Energy Cost | $ 30.00 | per kW/Year | All-in Price at Capacity Factor of 25.00% | $ 68.43 per MWH |
| Capacity Price | $ 84.17 | | | |

| | Capacity Percent | Energy Val per kW | Capacity Cost/kW | Net Capacity Value/kW | Capacity Value Deviation | Capacity Factor |
|---|---|---|---|---|---|---|
| Peakers | 79.70% | $ - | $ 84.17 | $ 84.17 | $ 4.73 | 45.68% |
| Combined Cycle | 14.60% | $ 70.96 | $ 151.50 | $ 80.54 | $ 33.64 | 90.00% |
| Coal | 5.70% | $ 161.62 | $ 255.94 | $ 94.32 | $ 63.58 | 90.00% |
| Average | | | | $ 86.34 | $ 101.95 | |
| Reserve Margin | 15.00% | | | | | |

### 5.4.7 Forward Price Simulation Models in Analysis of MPPs

Long-run marginal cost does not consider that construction behaviour of developers is somewhat unpredictable and may arguably be irrational in the short-term. If the ADB were to invest in merchant plants, forward pricing simulation models would have to be reviewed. A forward price simulation model can be used to demonstrate how risks associated with supply and demand; how different market frameworks affect costs and prices; drivers, construction of volatility, data requirements and technical heat rate issues. Unlike project finance valuation and financial modelling, market price simulation is very difficult to accomplish with spreadsheet analysis because of hour-by-hour dispatch, maintenance outage modelling, hydro operation, energy margin computations and optimization of new capacity. The following quote demonstrates how Moody's uses forward price simulation models developed by market consultants in evaluating merchant plant risks:

> The market study is intended to provide an assessment of the market structure and behaviour of participants that then allows a credible projection of market prices. The predictive power of a market study is only as good as the assumptions that underlie the analysis. Since the ultimate goal of the market study is to predict the price of power, most studies use economic forecasts to derive demand and focus on the supply elements.
>
> Moody's relies on issuers and market consultants to provide us with forecasts of the future price of power. The key to this analysis is the cost of supply at any given level of demand. It is this underlying cost of all market suppliers of power that will be determinate in the market price of power. Consequently, a merchant

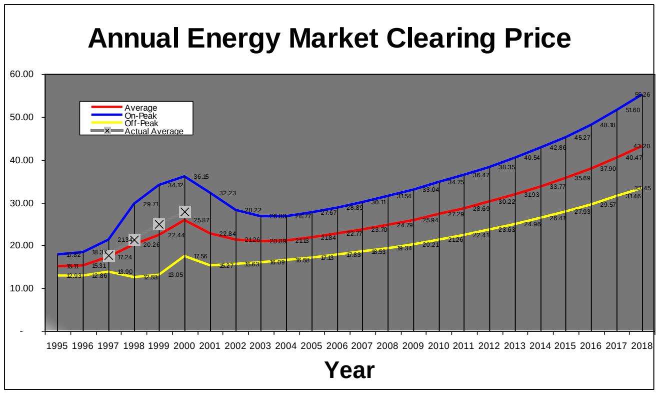
> plant's cost position relative to its current and potential competitors is one of the primary factors in assigning a rating. While determining the costs of a single plant is rather straightforward, determining its position relative to others and how each party may bid into an open power market is more complex.

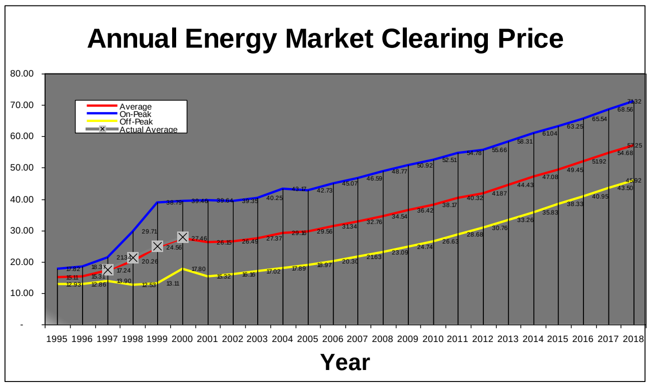
Forward price simulation models project market clearing prices using estimates of hourly loads and plant data. The plant data includes fuel prices, maintenance outages, variable operation and maintenance, plant heat rates, existing thermal capacity, pumped storage hydro capacity and transmission constraints on imports and exports for a market region. The databases of loads and power plants are used in a dispatch module that simulates the hourly operation of power plants. Forward price models differ from the simple marginal cost models described above in three respects. First, the models account for existing supply and predict prices when the market is not in equilibrium – when there is excess or deficient supply and when the capacity mix is not optimal. Second, the models include capacity prices and account for the relationship between capacity and energy markets. Third, the models can simulate the volatility of prices as well as the expected level of prices.

To introduce forward price models, we present alternative scenarios for the Philippines case study. In the first scenario, the assumption is made that capacity reaches equilibrium as demand grows. In the second scenario, developers are assumed build more capacity than is implied by equilibrium and in the third case demand grows faster than the base case. This type of analysis of merchant plants is representative of actual analysis as illustrated in the following quote:

> Power rate consultants assume long term generation demand and supply will be in equilibrium. Moody's agrees with that assumption, but assumes that in certain years overbuilding or an economic recession will create an excess generation capacity situation. A good example of a current overbuild situation is northern Chile where burgeoning supply far exceeds expected demand. Other examples may evolve in New England or near Chicago where significant numbers of new plants have been announced.

The two graphs below illustrate how price trends are dependent on outlooks for the behaviour of developers. The first graph shows an overbuild scenario where developers build more capacity than is justified in order to earn their cost of capital. The second graph shows a situation where demand increases no overbuild occurs. The first chart shows that after a capacity overbuild, it can take many years before the market reaches equilibrium, which can have several financial consequences to an MPP. The two graphs illustrates that the time it takes to reach equilibrium after an over-build scenario can dramatically affect the value and the credit quality of a merchant plant.




## 5.5 Risk Assessment of MPPs

### 5.5.1 Introduction

Given the volatility of electricity prices and the potential for downward movement in prices one may wonder whether why any investment – particularly debt investment -- is made in MPPs. However, according to Standard and Poor's: "merchant power plants, mining projects, and oil and gas projects that produce and sell volatile commodities have raised billions of dollars of non-recourse rated project finance debt without the benefit of traditionally structured off take contracts." The question therefore is not whether MPPs are too risky, but rather how to measure risk so that ADB loans, equity investments and insurance products are appropriately priced to reflect the risk.

Analysing risks in a rigorous manner is the central issue the ADB must address when investing in the merchant power industry. Risk analysis already been considered in the discussions of volatility, break-even analysis, sensitivity analysis, probability of default and carrying charges. In this section we describe how some of the most important risks faced by MPPs can be quantified. These risks include demand variability, fuel constraints and price volatility, hydro yield variation, developer behaviour and the uncertainty in the productivity and reliability of new technologies. The discussion of various different risks allows the ADB to evaluate different MPP investments in various countries. For example, if a country has relatively low demand variability, the ADB can consider how the low demand risk affects cash flow volatility and what underwriting and pricing standards should be implemented.

Similarly, if a country has high hydro volatility, the ADB can determine how debt leverage, debt service benchmarks and policy recommendations should be adjusted relative to countries without significant hydro risk.

Financial economists often separate risks into various categories when evaluating investments under uncertainty. A first risk category -- market risks – consists of those risks driven by variables such as commodity prices and interest rates. These risks can often be hedged through forward contracts and other derivatives. A second risk category -- strategic risks -- is associated with the business activities embarked upon by a company. These risks must be incurred by a business in order for the company to earn economic profit. Other categories of risks include regulatory risks, financial risks, contract risks and construction risks. In the remainder of the report we discuss four general risks faced by merchant power plants. These include: (1) market risk including the sale price and dispatch of electricity and the cost of fuel; (2) project risk including technology, construction and operating risks; (3) strategic risk driven by decisions made by MPPs; and, (4) risks associated with bilateral contracts.

Each of the risks affects the question of how much future revenues derived from prices of electricity and dispatch quantities faced by an MPP will deviate from expected levels. Risks may affect both the volatility around prices for a short period and long-term trends in the price of electricity. Issues associated with physical dispatch, price volatility and price trends for MPPs overwhelm construction cost, operation and maintenance and interest rate risks that are important in underwriting plants with long-term contracts. For each risk category we first describe how the risk affects prices on from a qualitative standpoint. Next, we discuss mathematical techniques that can be used to measure the risks. Finally, we consider how the risk can be quantified in terms of the cash flows and credit quality of MPPs.

### 5.5.2 Market Risks from Electricity Demand Uncertainty

In making investments in merchant power plants, the ADB will need to develop a framework to project the range in possible prices. One method is to make judgemental assessments as described above. A second method involves applying estimates of the volatility of demand, fuel price and supply factors from objective historic data and evaluating the volatility of future prices. Unlike plants with long-term purchase contracts, merchant plants must absorb risks of demand fluctuations, fuel prices, developer behaviour, plant outages, hydro variation and other factors. Volatility estimates can be developed for all of these inputs and the volatility of power prices can be evaluated.

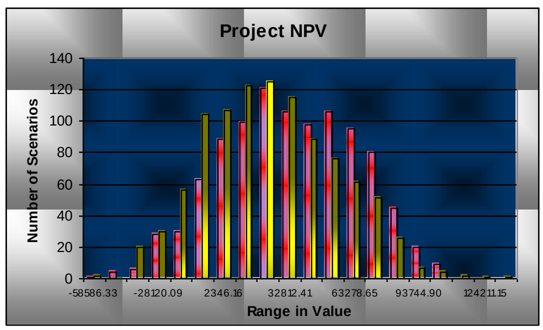
We begin the discussion of specific risks by considering market risks that are outside of the control of investors in merchant plants. Three risks that affect the cash flow of merchant plants and were insulated from IPP's with long-term contracts include risks associated with demand growth, risks that occur because of fuel price swings, and risks that arise from changes in the hydro energy from river flow fluctuations. The following statement demonstrates how market risk affects the credit rating of an MPP:

> In an era of competitive power when merchant generators are assuming risks of price and dispatch (volume) ….the presence of electricity market risk in a project is often a constraint in obtaining an investment-grade rating, especially for single-asset plants that have no portfolio diversification.

Demand risk affects MPPs in two important ways. First, the level of demand can

affect the amount by which MPPs are dispatched. Second, the level of demand relative to supply can dramatically affect prices for long periods of time. An example of the first type of risk – capacity factor variation -- is the possibility that a peaking plant will not run because of moderate weather. An example of risks associated with supply and demand imbalance is the risk that demand will below expected levels and an MPP will face low prices for an extended period of time because of excess capacity in the market.

The effects of volume risk are illustrated using the combustion turbine case study. In the first case there is no uncertainty associated with demand risk and the price uncertainty uses the 25% volatility assumption above. In the second case, volume increases or decreases in a random manner representing the way in which extreme weather affects the dispatch of peaking plants. The first graph shows the distribution of the present value of project cash flows with and without volume risk. The table below the chart demonstrates that volume risk more than doubles the credit risk of the peaking plant.



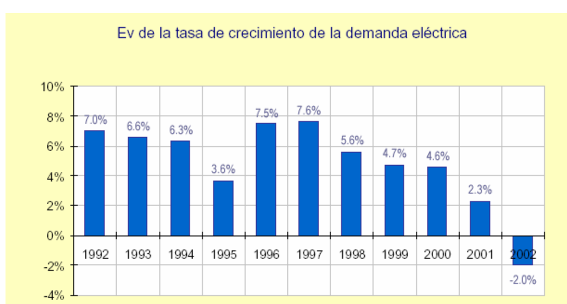

| | CT Plant | |
|---|---|---|
| | Without Volume Risk | Including Volume Risk |
| **Results** | | |
| Credit Pricing | | |
| Probability of Default | 28.60% | 92.70% |
| Loss, Given Default | 11.06% | 17.90% |
| Required Credit Spread | 3.16% | 16.59% |
| | | |
| **Assumptions** | | |
| Electricity Price | | |
| Price Volatility | 25% | 25% |
| Price Trend | -1% | -1% |
| Debt Characteristics | | |
| Leverage | 60% | 60% |
| Term of Debt | 15 | 15 |

Demand risks facing an MPP are very different than demand risks facing plants that operate in a regulated or stated owned system or plants that have long-term fixed price contracts. In regulated or state-owned systems, if changes in demand cause there to be surplus or deficient capacity in a market, higher or lower rates are generally imposed on consumers. Similarly, if electricity generation plants have fixed price contracts, the cash flow of the plant does not change when overall demand of the electricity system changes. This is not the case for merchant plants. In both the short-run and the long-run the cash flow for a merchant plant depends on how demand affects the market price and how demand affects the level of dispatch. For a

given level of capacity, if demand is lower than expected, the price and capacity factor will fall while if demand is higher than expected, the price and the capacity factor increases. The following statements by investment analysts of MPPs illustrate the importance of considering demand risks:

> Merchant power plants (MPPs) face volume risk. This risk was traditionally absorbed by the utility, but in an uncontracted world each individual generator will be subject to the hour-by-hour fluctuations in the demand for power.
>
> A longer-term element of volume risk is the growth of electricity demand in the area in which a plant can supply power. This analysis is tied to the economic viability of a city, state or region compared to other areas, and focuses on broad demographic trends. Likewise, questions regarding individual demand for power or per capita consumption of power would affect a merchant plant. All of these questions would need to be answered on a market-by-market basis if there is more than one merchant generating station, or for the single market in the case of a single asset generating station.
>
> Demand growth assumptions not only determine assumed electricity needs over time, they also determine the region's changing generating plant mix. As discussed below, given that industry participants expect future new generation will overwhelmingly take the form of simple cycle or combined cycle gas-fired plants, regions predicted to experience great demand growth will more quickly become dominated by gas-fired generation than will regions predicted to experience slower demand growth. A region's equipment mix will, of course, affect that region's variable and fixed generation cost assumptions.

The way in which an MPP faces demand risk can be demonstrated by the history of demand fluctuations that have occurred in Asian electricity systems over the past decade. Part 2 of the MPP report documents the way in which demand changed because of the Asian crisis. The swings in demand before and after the Asian economic crisis would have had dramatic effects on spot market prices had competitive systems been in place. The surplus in capacity that occurred after the crisis would have depressed prices for many years. A specific example of demand risk faced by MPPs through unexpected long-term trends is illustrated by the case of Argentina below. If an MPP had been contemplating an investment in 1977, it may have been reasonable to anticipate growth of 6% to 7% per year. However, actual growth turned out to be much lower. The lower growth means that reserves were much higher than anticipated and that the prices and capacity factors experienced by cycling and peaking plants would also have been lower than anticipated.

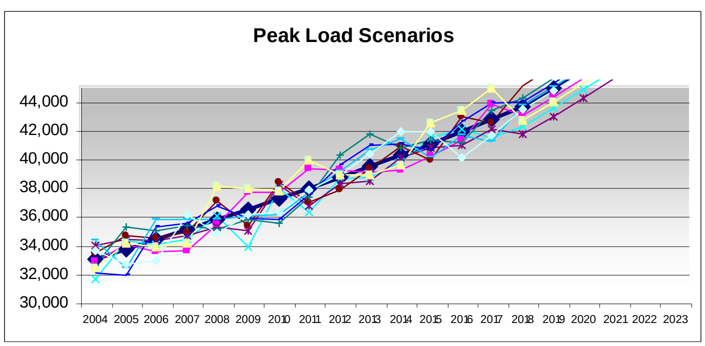



Alternative methods can be used to quantify demand risk including scenario analysis

that incorporates judgement and macro-economic information and statistical analysis of historic trends that use volatility and simulation. The potential for long-term changes in demand is driven by the state of the economy and changes in use of electricity caused by different industry structures. Such changes in long-term trends are difficult to assess by examining historic trends in sales data. Problems with use of extrapolation are demonstrated by the Asian crisis wherein changes in electricity demand would not be predicted from analysis of past trends. In analysing long-term demand we recommend that the underwriting process begin with statistical analysis and then used scenario analysis to consider the potential for lower than expected demand.

Short-term changes in demand create risk in the cash flow of an MPP due to the manner in which demand changes affect both the spot price and the level of dispatch. These changes in demand are generally driven by weather as well as changes in economic activity. If the weather is warmer than expected in the summer, the demand will generally be higher. In this case, the electricity price and the cash flow of a merchant plant will also be higher. The weather driven changes in demand can be quantified with statistical analysis through applying volatility statistics to the long-tem demand projections. The volatility statistic is computed in the same manner as for prices described in Appendix 1, except that the data for making the mathematical calculations is first seasonally adjusted.

To incorporate demand risks into the underwriting process for an MPP, demand forecasts that incorporate risk must be included in evaluation of price trends. Inclusion of risk involves accounting for both the potential for structural changes in economic activity and short-term volatility. The long-term volatility is generally measured with scenario analysis while short-term risk is driven by volatility measurement. An example of how different long-term price projections and short-term volatility can be used to measure risk is illustrated in the graph below which applies Monte Carlo simulation to reflect the short-term weather related volatility. As with the graphs that apply volatility to market prices shown in Section 5.4.4, only a few of the multiple scenarios are shown on the graph.




Once the long-term demand scenarios and the volatility parameters are established, the data becomes an input to forward price simulation models. Using the example in the graph above, the variation in demand data would drive the computation of price and dispatch in many applications of the forward price simulation model. Since multiple demand paths result from application of the volatility in the demand analysis and from construction of alternative long-term scenarios, and since each demand path results in a different price path and capacity factor projection, multiple potential

MPP cash flow projections result from this process.

### 5.5.3 Market Risks from Fuel Price Uncertainty

A market risk faced by MPP investors other than demand risk involves the possibility that fluctuations in the price of fuel can negatively impact the cash flow of a plant. Changes in the price of fuel price affect the MPP risks because of the manner in which fuel prices affect both revenues and operating costs. The reason fuel price risk affects revenues is illustrated by the way profit margin earned on from a merchant coal plant depends on gas prices because of the way gas prices affect electricity prices. Alternatively, the profit margin on a gas plant can be affected by the price of gas in hours when the price of electricity is driven by the oil price. Fuel price risk is discussed in the following statement by Moody's:

> The assumptions regarding fuel costs are very important to a system that has a variety of plants powered by different fuel types. If a fuel is considered to be "on the margin" it is the system marginal price setting plant and therefore, as its fuel costs go up, so does the price of electricity in that market. With regard to the general level of fuel prices, Moody's looks at gas prices in market studies since gas is tending to become the system marginal fuel in many markets for an increasing percentage of the time. A contentious assumption with market studies in general is the fact that the price of natural gas will increase at a rate above the general rate of inflation. This accelerated pace of price increases is attributed to the greater demand for natural gas as a more environmentally friendly fuel relative to other fossil fuels and to transportation constraints in markets of high demand.

In underwriting MPP loans, the ADB must account for the manner in which fuel price risk occurs in different electricity systems. In some countries the predominant fuel may be coal with very low price variation while in other countries there may be diversity in fuel where the price of oil drives spot prices in some hours, the price of gas drives the market price in other hours and the price of coal influences price in off-peak hours. In the latter situation, the ADB must account for how price variation influences both the revenues and the operating costs of an MPP.

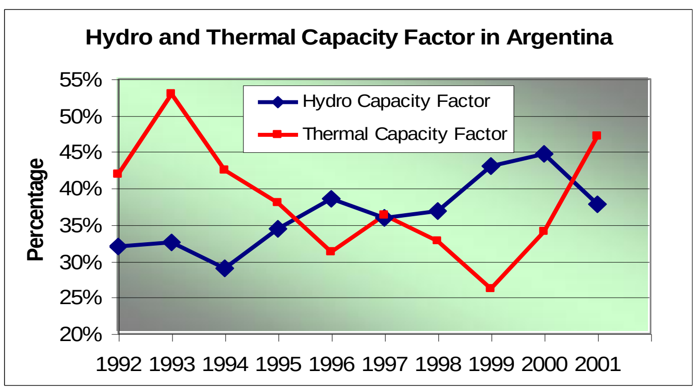
Long-term trends and the volatility of fuel prices can be gauged in a similar manner as the analysis of electricity prices above. In some cases, forward markets exist for fuel price as is the case with natural gas prices in the US. Forward prices can be used as the basis for making projections of long-term prices. In cases where forward markets for fuel exist, options are also often traded. The price of these traded options can be used to derive what the market thinks future price volatility will be.

Quantification of fuel price risk effects on the cash flow of an MPP can be accomplished using the tools discussed above involving volatility, price trends and simulation. As is the case for incorporation of demand risk in MPP analysis, the representation of fuel price risk is entered into forward price simulation models. Once trends and the volatility of fuel is input in forward price models, the manner in which fuel price volatility affects the fuel cost, dispatch level and the market price faced by an MPP can be evaluated. The resulting cash flow volatility can be combined with other sources of risk including demand risk to assess the distribution of possible cash flows that can result from an MPP investment.

### 5.5.4 Market Risks from Hydro Uncertainty

A third market risk faced by MPP investors involves risks associated with the variation in energy produced from hydro plants. This is particularly the case with run of river hydro schemes, or those with relatively small storages. Large hydro storages can be used to transform volatile inflows into more steady outflows for generation, even through drought sequences dependent on the operating policies in place. As with demand risk and fuel price risk, variation in hydro generation affects both market clearing prices and the dispatch of MPPs. Hydro production is uncertain because of variation in the river flows driven by weather (e.g. snowfall in mountains and droughts) and other factors. Since hydro plants have no fuel cost, the production from hydro will displace the energy production from MPPs that rely on fossil fuels such as natural gas or oil. Further, since hydro production influences the dispatch order, hydro risk also influences spot market prices and the revenue earned by an MPP.

The impact of hydro capacity on price volatility was demonstrated in the discussion of volatility in Section 5.4.3 above. The manner in which hydro risk affects the dispatch of an MPP is illustrated by the case of Argentina shown in the graph below. This graph shows that the capacity factor of hydro plants moves in the opposite direction to the capacity factor of thermal plants. In those years in which the capacity factor is higher for hydro plants, the capacity factor is lower for thermal plants as expected because there is less need to run the thermal plants. The more the hydro capacity the more the fluctuation in thermal operation that occurs from the variation in hydro generation. The reduced capacity factor of thermal plants directly affects MPP revenues as does the lower price that result from increased hydro production.




Unlike risks associated with demand and with fuel prices, hydro risk can be directly assessed using analysis without additional scenario analysis driven by judgement. Statistics computed from long term data series of the capacity factor of hydro plants can compute mean levels of hydro production and the volatility of hydro generation. For example, in the example of Argentina illustrated above, forward prices analysis would incorporate the expected capacity factor as well as the volatility of capacity factor. Hydro risk can be quantified in the underwriting process of an MPP by incorporating volatility and expected levels in the forward price simulation models. Once average levels and the volatility of hydro is input in forward price models, the manner in which hydro volatility influences MPP dispatch and the market price faced by an MPP is assessed using Monte Carlo simulation. For random draws that imply a high level of hydro output, the market price declines while for random draws that drive the hydro output to low level, the MPP financial position improves.

### 5.5.5 Business Strategy Risks

The most important factor driving the financial meltdown that has occurred in the merchant power industry around the world has generally not been demand, fuel price or hydro risks. Instead, financial distress in the UK, Argentina, the US, and Australia has been driven by the behaviour of MPP developers themselves. In each of these situations, the amount of capacity built in the market exceeds the amount that keeps prices at a level that enables a reasonable return to be earned on new capacity. Surplus capacity resulting from the behaviour of developers in these cases will likely keep prices below long-run cost for many years. Other risks that can affect prices in the long-run involve the possibility that changes in the technology and the real capital cost of new plants will drive prices lower.

Investors in the debt and equity of MPPs have commented on risks related to the productivity of new plants as follows:

> Suppliers of new and cheaper power generation, including more efficient and technologically advanced units, may represent the greatest threat to an MPPs cash flow. New supplies may com from Greenfield projects, renovation or expansion of existing facilities, or additional access to transmission. ***If new capacity enters the MPPs service territory, the potential exists for electricity prices to fall, especially if new generation capacity leads demand and seeks only to gain market share within a static market.*** Insofar as new competitors can produce power more cheaply, MPPs margins may erode as marginal power costs fall. Moreover, even if new competitors' cost structures differ slightly from those of existing generators, the mere fact of the capacity addition will lower prices, extract market share, or both.
>
> There is considerable uncertainty over where [UK] pool prices will go ….A lot of merchant power plants are … relying on efficiencies in technology and the low cost of fuel. But technology improves very quickly and so their relative position in the pool can change substantially.
>
> In attempting to minimize the risk associated with the future market price of electricity in the region to be served by the proposed merchant plant, several considerations must be addressed, ***including the presence-actual or likely-of other generation providers within the region***, the likelihood of electricity imports from outside the region, transmission constraints and the future regional demand for electricity….In making these assessments, one needs to consider the availability and location of potential generation sites, the financial and marketing strength of potential competitors, the possibility that any competitor will utilize a production technology that is more efficient than that of the proposed plant, and the potential for regulatory changes, such as opening a region to imported power from neighbouring regions.

Assessing the risk of merchant behaviour and technology changes cannot be accomplished in a reasonable manner by analysing historic data. Instead, the risks must be assessed using expert judgement about the industry and by creating alternative scenarios with respect to new developer behaviour and changes in technology. The scenarios require knowledge of other developers in the market and evaluation of the potential for future overbuilds. The way in which overbuilt capacity can influence market prices is illustrated in the graph which assumes overbuilds of 10%, 20% and 30%. In each case, the demand growth eventually eliminates the

surplus capacity and the market reaches equilibrium when new capacity is required. The larger the surplus, the lower the market price and the longer it takes for the market to reach equilibrium.

Risks of potential technology changes that could impact long-term prices can be evaluated by computing long-run marginal cost as described in Section 5.4.6. The table below compares long-run marginal cost under four different scenarios. The first scenario assumes no productivity improvement, the second scenario assumes a 10% reduction in heat rate, the third scenario assumes a 10% reduction in the real cost of constructing capacity and the fourth scenario assumes a 10% reduction in both heat rate and capital cost.

**LRMC With Different Assumptions in $/MWH**

| | Base | 10% Improved Heat Rates | 10% Improved Real Cost | 10% Improved Heat Rates and 10% Improved Real Cost |
|---|---|---|---|---|
| Price at Average Load Factor | | | | |
| Price in $/MWH | 38.79 | 37.39 | 36.47 | 35.29 |
| Percent Reduction from Base | | -3.61% | -5.98% | -9.02% |
| | | | | |
| Price at 100% Load Factor | | | | |
| Price in $/MWH | 33.99 | 32.79 | 31.92 | 30.97 |
| Percent Reduction from Base | | -15.47% | -17.71% | -20.16% |

## 5.6 MPP Credit Analysis and Benchmarks for MPP Financial Structuring

### 5.6.1 Introduction

Given the above description of general risks facing MPPs we move to the subject of credit risk which is the basis for underwriting and pricing ADB loans for MPPs. Analysis of credit risk establishes: (1) a basis for pricing of ADB loans to MPPs; (2) appropriate financial ratio benchmarks for MPPs; (3) financial structure enhancements such as covenants and debt service reserves to apply to MPP loans; and, (4) the nature of bilateral contracts and risk hedging mechanisms that should be incorporated in MPPs. Our discussion of credit analysis begins with a general overview of measuring credit risk and pricing loans. Next, tools to measure the credit risk of MPPs including volatility of cash flow and Monte Carlo simulation are described. Given these MPP analysis tools, the final parts of this section address debt service ratio and debt to capital ratio benchmarks the ADB should apply to prospective MPPs.

### 5.6.2 Theory and Measurement of Credit Risks and Credit Spreads

Traditionally, credit analysis has involved developing standards to classify loans into a number of different risk categories. This classification includes bond ratings of credit rating agencies with letter rankings and credit scoring in banks with numeric grades. The credit scores should be correlated to the chance of loans not being repaid (bond rating agencies such as Standard and Poor’s and Moody’s regularly publish correlations between their bond ratings and the probability of default to demonstrate the validity of their risk rating systems.) Credit scoring systems generally involve assessing financial ratios (such as the debt service coverage ratio) and determining whether key credit risks can be mitigated. Credit risk also accounts

for the collateral and the chances of recovering money once things go wrong.

Modern credit analysis is founded on the notion that risky debt has a payoff structure that is similar to the seller put option. There is downside risk which can cause lenders to loose up to the loan amount (driven by the volatility of cash flows) and an upside payoff that is limited to the credit spread. The option analysis can be used to directly measure credit spreads – the cost of capital on risky debt – by measuring the probably of default and the probability of recovering money once a default has occurred. The latter amount is known as the loss given default. Much of modern credit analysis involves measuring the probability of default and the loss given default because the credit spread can be quantified in the following formula:

| Credit Spread = Probability of Default x Loss Given Default |
|---|

In evaluating a power plant with a long-term purchased power contract, the probability of default is primarily driven by the chances of a default on the power contract. The reason that the power contract characteristics drive risk assessment is that other risks are generally moderated by using conventional in constructing the plant, purchasing insurance for contingencies ranging from business interruption to political risk, signing O&M contracts to mitigate O&M risk and by using interest rate swaps to mitigate interest rate risk. With risks transferred to other parties, the risk that remains is the risk that the purchased power contract will not be honoured because of financial insolvency of the off-taker. Therefore, a typical rule of thumb in projects which have a long term power purchase contract is that the project has a bond rating one notch below the bond rating of the off-taker. In terms of the above formula, the probability of default on the project is a direct function of the probability of default on the off-taker.

In contrast to projects with long-term contracts, the probability of loss and the loss given default cannot be approximated from the bond rating of another company. Instead, credit analysis of an MPP requires direct assessment of the probability of loss and the value of collateral if a default occurs. In order to quantify probability of loss and loss given default the volatility and price trends must be used together with a project finance model. The greater the volatility of prices and the greater the chances for downward trends in the market clearing price, the higher the probably of loss and the higher the loss given default. Further, the loss given default and the probability of default are directly affected by financial structuring of the MPP related to covenants and debt service reserves.

### 5.6.3 Mathematical Assessment of Credit Risk

The theory of establishing credit is straightforward in theory, but in order to be useful, one must be able to reasonably apply the method in practice. Credit spread can be computed for a competitive electricity plant by applying the following step-by-step process:

**Step 1:** Estimate free cash flow and loss given default through constructing a project finance model that incorporates debt structuring elements such as covenants, debt service reserves and anchor contracts.

**Step 2:** Develop a measure of probability of default through applying Monte Carlo simulation to time series analysis using volatility parameters.

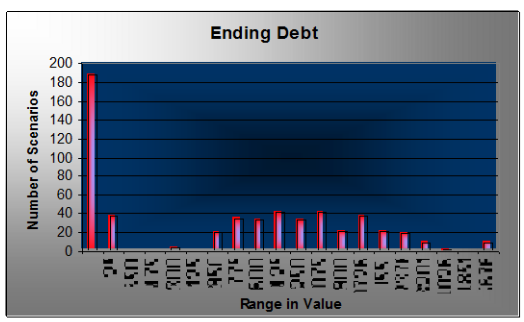
**Step 3:** Measure the expected debt loss from probability of loss multiplied by the

probability of default and incorporate bankruptcy cost.

**Step 4:** Assess the credit spread by using an iterative technique to equate the benefits to debt holders from receiving a yield above the risk free rate with the expected value of loss on the project finance debt.

The first step in computing the credit spread is to develop a model that measures the loss on debt from downside market price cases. The amount of debt that cannot be paid from free cash flow of the project is the basis for measuring the probability of default and the loss given default. The measurement can be accomplished by creating a project finance model that is structured so as to measure the potential loss on debt after a default has occurred. This means if the electricity prices are low enough in a year to cause a default on debt service, positive cash flows in future years should be applied to make up the previously accrued debt service on a loan. If electricity prices remain low enough so that the accrued debt service cannot be paid at the end of the project life, the accumulated loss in debt service is the loss given default.

Using forward price scenarios and the combined cycle plant from the case study, the distribution of possible loss is shown in the table below. Most of the cases have no loss on debt. In the cases were a loss on debt occurs, the amount of debt that is not repaid ranges from almost nothing to the full amount of the loan. This distribution can be used to compute the expected loss on debt by averaging the loss across all of the scenarios. In the below graph, the expected loss is $7,316 relative to the loan size of $156,784. Dividing the loss by the amount of the loan implies that the credit spread must be 4.76%. The probability of loss – the chance that the debt will not be fully repaid -- in the above graph is 32%. Dividing the credit spread by the probability of loss implies that the loss given default percent – the average amount that is lost when a default occurs -- is 15%.



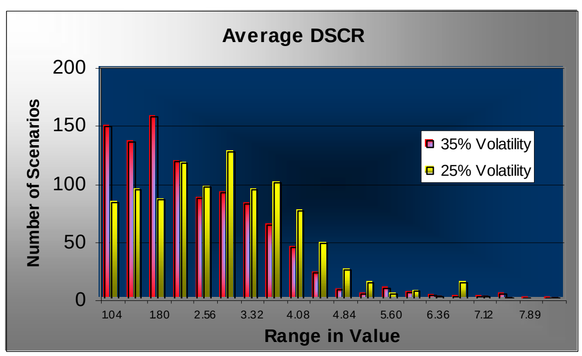

The amount of debt outstanding at the end of the life of a project depends on the structure of debt. If the debt has covenants and debt service reserves that effectively “capture” all of the free cash flow before any cash is distributed to equity holders as dividends, the calculation of loss given default is simplified. In this case there is no leakage to equity and the present value of debt service can be compared to the present value of free cash flow in measuring loss given default. With the structure where all debt is paid off before any cash is distributed to equity holders, if the present value of the free cash flow from a price path at the after tax debt rate is greater than the value of the debt, then there is no loss. On the other hand, if the present value of free cash flow is less than the value of the debt, the loss given default incurred by the debt holders is the difference between the present value of the free cash flow at the risk free rate and the value of the debt itself. In a single

scenario, the loss in debt value is given by the formula:

| |
|---|
| Loss Given Default = Maximum (Present value of free cash flow at Rf – Face Debt, Zero) |

The numbers from a project finance model with a single scenario provide information about risk and the probability of default. The second step incorporates probability of default into credit analysis. The probability of default can be measured by using the project finance model together Monte Carlo simulation and volatility parameters. Adding risk to the project finance modelling requires that a time series of prices defined by volatility and other parameters must be simulated. Without applying Monte Carlo simulation, there is no way to gauge how the probability of default is affected by differences in risk. For example, if there is no accounting for volatility, the probability of default would be the same in a case where prices are fixed by a long-term contract as it is if the prices are subject to very volatile market swings.

Using Monte Carlo simulation, probability of default is the number of simulations where the loss on debt is greater than zero divided by the total number of simulated price paths. A default occurs when cash flow cannot pay off debt in a single year. This can be measured using the debt service coverage ratio. When the minimum debt service coverage ratio is below 1.0, a default has occurred. A distribution of the debt service coverage ratio for the various simulations is shown in the graph below for a volatility level of 25% and 35%.




The third step of the process is measuring the expected value of the loss on debt. Since the interest rate on debt (including the credit spread) is known beforehand in a transaction, the expected value of loss on debt is the probability of default multiplied by the loss given default. Using the Monte Carlo simulation, the expected loss is computed by averaging the loss in each scenario. This loss must be gauged against the credit spread that is incorporated in the loan and realized when the loan does not incur a loss.

The final step of the credit analysis is to evaluate pricing or the credit spread on ADB debt given risks of cash flow. This credit spread equates the benefits – higher earnings to the holders of project finance debt in non-default scenarios – with the costs – the probability of default multiplied by the loss given default. The benefits are the earned yield above the risk free rate in scenarios that do not have a default. The costs are the loss incurred on the debt. The remainder of this section includes a number of examples where costs of incurring a loss on debt and benefits of increased credit spreads are used to assess ADB pricing at different levels of volatility with different assumed debt leverage.

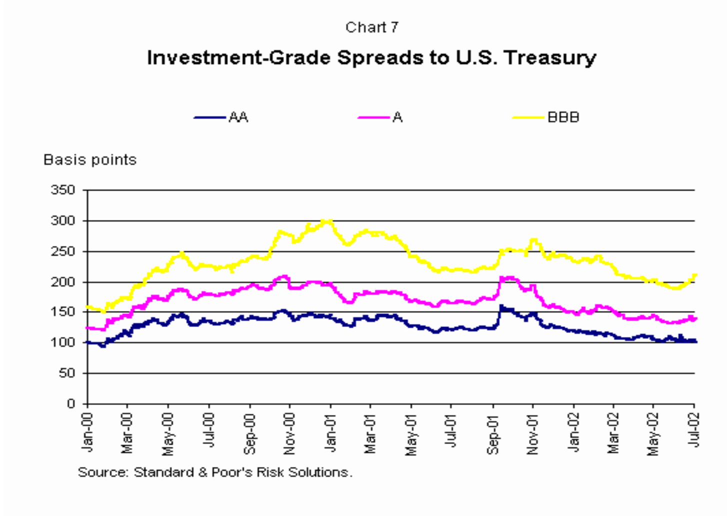
## 5.6.4 Financial Ratio Benchmarks in Credit Analysis

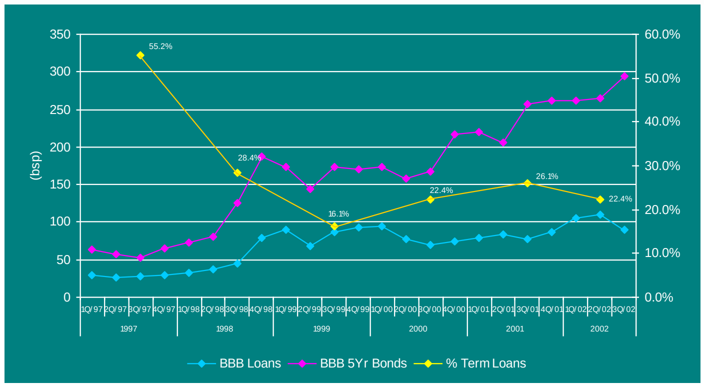
In formulating policy when making plant investments, the ADB can use financial ratios to establish risk acceptance criteria that screen potential MPP investments for further analysis. Financial ratios should not be used as absolutes in accepting or rejecting the credit quality of an MPP or any other investment. Rather, the benchmarks can provide a guide as to the level of additional analysis that may be required in underwriting a loan. For example, if a merchant plant exceeds debt service coverage ratio and debt leverage ratio benchmarks by a wide margin, less analysis of forward price simulation models and the operating characteristics of merchant plant may be required. In the discussion below we consider benchmarks for two financial ratios – the debt service coverage ratio and the debt to capital ratio.

In setting benchmarks, the ADB could roughly gear the credit quality of MPP debt to an investment grade level. This means that debt service coverage levels and debt to capital ratios would be set at levels that correspond to investment grade bond ratings. In theory, the credit rating of a bond corresponds to the probability of default discussed above. Indeed, bond rating agencies regularly publish the actual default rates of various classifications. The chart below illustrates the probability of default for various bond rating categories published by S&P. For BBB 15 year issues, the probability of default is 4.27%.

| | Year | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Quality | 1 | 2 | 3 | 4 | 5 | 10 | 11 | 12 | 13 | 14 | 15 |
| AAA | 0.00 | 0.00 | 0.04 | 0.08 | 0.13 | 0.67 | 0.67 | 0.67 | 0.67 | 0.67 | 0.67 |
| AA | 0.01 | 0.04 | 0.11 | 0.21 | 0.33 | 0.90 | 0.94 | 0.98 | 0.98 | 0.98 | 0.98 |
| A | 0.04 | 0.11 | 0.18 | 0.31 | 0.47 | 1.48 | 1.68 | 1.78 | 1.84 | 1.88 | 1.92 |
| BBB | 0.21 | 0.48 | 0.77 | 1.28 | 1.81 | 3.63 | 3.81 | 3.94 | 4.09 | 4.20 | 4.27 |
| BB | 0.91 | 2.82 | 5.00 | 7.04 | 8.82 | 14.42 | 15.19 | 15.55 | 15.84 | 15.84 | 15.84 |
| B | 5.16 | 10.90 | 15.36 | 18.60 | 20.95 | 27.13 | 27.54 | 27.76 | 27.83 | 27.83 | 27.83 |
| CCC | 20.93 | 28.04 | 33.35 | 36.83 | 40.67 | 44.23 | 44.23 | 44.23 | 44.23 | 44.23 | 44.23 |

Market data on the expected default probability and the loss given default can be derived from market credit spreads. The graphs below illustrate that credit spreads for BBB bonds have been ranged between 2% and 2.5% in recent years. This market data along with the probability of default from above implies a loss given default of 58%. In the analysis below, we compute probability of default rates and loss given default rates that correspond to this market data on credit spreads for investment grade bonds.




### *Debt Service Coverage Ratio Benchmarks*

The primary quantitative ratio used to asses credit quality in a project finance transaction -- for a merchant power plant or for a plant with long term contracts -- is the debt service coverage ratio. This ratio is effective in evaluating project finance transactions because of the manner in which these project finance are driven by cash flow. In project finance, cash flow is applied to debt service and cannot generally be used for other new investments as in corporate finance. Further, the ratio that includes both interest expense and debt repayments is an effective measure because debt service is generally customized to the cash flows of a project. If the debt service coverage ratio is below 1.0, the cash flow of a project is not sufficient to cover the interest expense and debt re-payments that are due to lenders.

This section considers debt service ratio benchmarks the ADB should establish for MPPs in the underwriting process. Due to the importance of the debt service ratio, benchmarks are considered for various variants of the debt service coverage including the minimum debt service coverage ratio, the short-term debt service coverage ratio, the average debt service coverage ratio, the senior debt service coverage ratio, the junior debt service coverage ratio and the loan life coverage ratio. Before describing the benchmarks, the various different versions of the debt service coverage ratio are defined. After these definitions are established, benchmarks are recommended for various ratios.

### ***Definition of Debt Service Coverage Ratios***

Before discussing the level of benchmark for debt service coverage ratios, we define the debt service coverage ratio. We also discuss issues associated with whether the benchmarks should be tied to minimum, short-term or average levels. Generally, stronger projects will show annual DSR's that steadily increase with time to partially offset the risk that future cash flows tend to be less certain than near term cash flows. The definition includes how debt service coverage ratio should be adjusted for senior and subordinated issues.

The general definition of debt service coverage ratio is revenues minus cash expenses, including taxes, but excluding debt service divided by debt service. The ratio can also be defined as cash from operations divided by principal and interest obligations where cash from operations is calculated strictly by taking cash revenues and subtracting expenses and taxes, but excluding interest and principal. The debt service ratio is generally computed on an annual basis. The ratio calculation also excludes any cash balances that a project could draw on to service debt, such as the debt service reserve fund or maintenance reserve funds. To the extent that a project has tax obligations, such as host country income tax, withholding taxes on dividends and interest paid overseas, etc., these taxes are treated as ongoing expenses needed to keep a project operating.

Over the life of a project and for different debt instruments that finance a project different debt service coverage ratios can be computed. Various debt service coverage ratios include:

**Average DSCR**: This ratio calculates the average CFO covered by the tenor of the debt and divides this sum by the average annual debt service. The average DSCR provides a general measure of a project's cash flow coverage of debt obligations.

**Minimum debt service coverage ratio**: The minimum debt service coverage ratio is the lowest level of debt service coverage over the life of the project. The minimum DSCR indicates the greatest period of financial stress in a project.

**Short-term DSCR:** The short-term DSCR looks forward three years for cash flow and debt service, and measures financial strength in the near-term.

**Loan Life Coverage Ratio (LLCR):** The LLCR computes the present value of cash flows over the debt tenor at the interest rate on debt as the numerator of the ratio. The denominator of the ratio is the present value of debt service at the debt rate. The denominator should equate to the amount of the debt.

**Project Life Coverage Ratio (PLCR):** The PLCR is similar to the LLCR except that the present value of cash flows is computed over the economic life rather than over the debt tenor. As with the LLCR, the denominator of the PLCR is the present value of debt service at the debt rate.

**Senior DSCR**: The senior DSCR is computed by divide the total cash flow of the project (before debt service) by only the senior debt service obligations. If only one class of debt exists, the ratio is computed exactly as it would for the DSCR.

**Subordinated DSCR**: The subordinated DSCR can be computed using consolidated cash flow and consolidated debt service or by computing the cash

flow after debt service divided by the subordinated debt service. The consolidated method calculates the ratio of the total CFO to the project's total debt service obligations (senior plus subordinated). This consolidated calculation provides the only true measure of project cash flow available to service subordinated debt. The second method takes the CFO and then subtracts the senior debt service obligation to determine the residual cash flow available to cover subordinated debt service. This method, does not, however, provide a reliable measure of credit risk that subordinated debt faces. A combination of small subordinated debt service relative to the residual CFO could result in a much higher subordinated DSCR relative to the consolidated DSCR calculation. Moreover, the ratio of residual CFO to subordinated debt is much more sensitive to small changes to a project's total CFO than the consolidated measure.

***Debt Service Coverage Benchmarks***

Benchmarks for the DSCR are more difficult to establish for MPPs than for projects with long term contracts because the DSCR depends on a forward electricity price projection which is inherently uncertain. Further, the benchmarks for MPPs depend on the anchor and other structural aspects of MPPs as described in the next section. For projects that transfer risks associated with electricity prices away from projects, the debt service coverage ratio can be lower than a project that includes price risk. In the more traditional contract revenue driven projects, rating agencies applied minimum base case coverage levels should exceed 1.3x to 1.5x levels for investment-grade ratings. For MPPs, these minimum levels are insufficient.

We recommend that the ADB apply a benchmark of 2.0x to the DSCR which is consistent with the analysis of bond rating agencies. The benchmark should be 1.5x if a bilateral contract covers the tenor of the project debt. The benchmark of 2.0x is demonstrated by the following statements of Standard and Poor's and Fitch:

**Standard and Poor's:** At a minimum, investment-grade merchant projects probably will have to exceed a 2.0x annual DSCR through debt maturity, but also show steadily increasing ratios. Even with 2.0x coverage levels, Standard & Poor's will need to be satisfied that the scenarios behind such forecasts are defensible. Hence, Standard & Poor's may rely on more conservative scenarios when determining its rating levels. In contrast Standard & Poor's considers that minimum DSCR threshold tests for most contract-driven projects to be around 1.30 times (x), provided that this figure holds under stress analysis.

**Fitch:** Based on merchant projects that Fitch has evaluated and rated, average annual debt service coverage of at least 2.0x, together with consistently high annual minimum debt coverage, is felt to be sufficient to support an investment-grade rating for a merchant power transaction without firm off-take agreements.

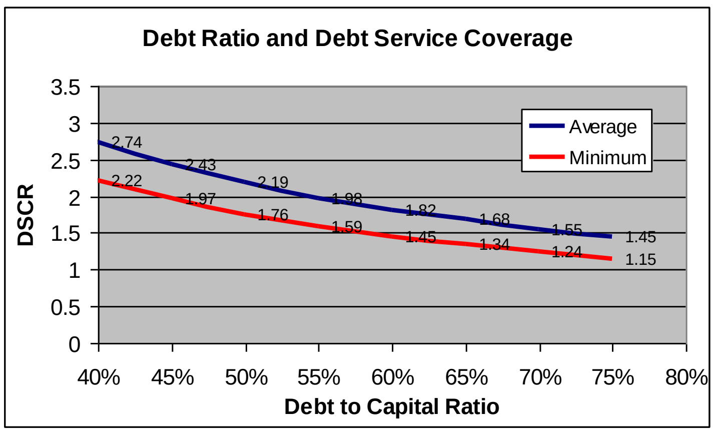
***Debt to Capital Ratio Benchmarks***

The debt service coverage ratio is a financial output in a project finance transaction which cannot be determined by sponsors of a project in advance. The debt service coverage ratio statistic can be driven my many factors including the debt to capital ratio. Unlike the DSCR, the debt to capital ratio is driven by a decision by sponsors and lenders. We have already discussed the fact that because of financial failures in

the MPP industry, projects with merchant exposure may find that leverage cannot exceed 50% if investment-grade rated debt is sought. This contrasts with contract-revenue driven projects, which typically have had leverage levels around 70% to 80%. Debt to capital benchmarks applied by rating agencies to MPPs are described as follows:

Because of the higher risk profile of merchant-generating assets compared with contractually based IPPs, Fitch takes the position that project equity should generally range between 25% – 50% of total capital, with the amount depending on the fundamental strengths of the project, certainty of cash flows, the capital structure employed, contracts, and the ability to reduce credit risk through hedging and marketing strategies.

There is a direct relationship between debt service coverage ratios and the debt to capital ratio once free cash flows have been established. The table above shows the average and minimum debt service coverage ratio for the combined cycle plant assuming that price levels for the plant result in a project IRR of 11.09%. The graph illustrates that a debt service coverage ratio of 50% is consistent with a minimum debt service coverage ratio of 1.76x and an average debt service coverage ratio of 2.19x.




As with the debt service coverage benchmarks, debt to capital ratios depend on structures in place to mitigate risk including rapid retirement of debt from early cash flow repayments, long-term sales contracts, and strong debt covenants and security provisions. For projects with no long-term sales contracts and a relatively weak structure we recommend a debt to capital benchmark of 50% while projects with anchor contracts, debt service reserves that cover more than a year of debt service, cash flow sweeps and cash flow traps can have a debt to capital benchmark of 65%. The table below illustrates the relationship between debt ratio, debt service coverage, probability of default, loss given default. The table shows that with price volatility of 25% and a downward trend in price of 1% per year, the 50% leverage is consistent with an investment grade bond rating.

| | NGCC Plant | | |
|---|---|---|---|
| | 50% Debt Leverage | 60% Debt Leverage | 75% Debt Leverage |
| **Results** | | | |
| Credit Pricing | | | |
| Probability of Default | 27.90% | 55.50% | 37.80% |
| Loss, Given Default | 9.09% | 8.41% | 20.21% |
| Required Credit Spread | 2.54% | 4.67% | 7.64% |
| DSCR | | | |
| Average DSCR | 2.19 | 1.82 | 1.45 |
| Minimum DSCR | 1.76 | 1.45 | 1.15 |
| Returns | | | |
| Project IRR | 13.64% | 14.78% | 17.95% |
| Equity IRR | 11.09% | 11.09% | 11.09% |
| **Investment Grade Benchmarks** | | | |
| Probability of Default | 4.27% | 4.27% | 4.27% |
| Loss Given Default | 58.55% | 58.55% | 58.55% |
| Credit Spread | 2.50% | 2.50% | 2.50% |
| **Assumptions** | | | |
| Electricity Price | | | |
| Price Volatility | 25.00% | 25.00% | 25.00% |
| Price Trend | -1.00% | -1.00% | -1.00% |

## 5.7 Structural Enhancements to Mitigate the Credit Risk of MPPs

### 5.7.1 Introduction

The most important aspect of ADB's underwriting process for an MPP will be determining whether the plant is economically sound. This means that the cost structure and the technology of the plant must be viable in relation to the existing electricity system in the country. However, once a plant is determined to be economically viable, the credit quality of a transaction can be enhanced by various structural features. The potential for structural enhancements to improve the credit quality of an MPP transaction is described in the statement by Standard and Poor's below:

Project structure does not mitigate risk that a marginally economic project presents to lenders; structure in and of itself cannot elevate the debt rating of a fundamentally weak project to investment-grade levels. On the other hand, more creditworthy MPPs will feature covenants designed to identify changing market conditions and other risks particular to MPPs and trigger cash trapping features to project lenders during occasional stress periods.

Structural enhancements to the debt of an MPP can be classified into two general ways. The first way to mitigate risk for debt holders is through financial enhancements. This form of financial structuring which can take the form of financial covenants, debt service reserves or subordinated debt to assure that the senior lenders receive as much of the free cash flow as possible before equity holders take out cash in the form of dividends. The second way to mitigate risk through structural enhancements is to shift risk away from the MPP to other parties through bilateral revenue and supply contracts. Some of the specific financial and contractual enhancements which could be applicable to merchant plant financing include:

- Financial Enhancements

- ✓ Cash flow capture covenants that cause debt to be re-paid early or debt service reserves to be built-up if debt service coverage ratios are low.
- ✓ Cash flow sweep covenants that cause debt to be re-paid early or debt service reserves to be built-up if cash flow is high.
- ✓ Debt service reserves that assure debt service can be paid if market prices or other risks cause cash flow to be low for an extended period of time.
- ✓ Subordinated debt and mezzanine finance that protects the cash flow coverage of senior debt instruments.
- ✓ Contingent equity or sponsor guarantees that provide for additional equity funding in downside cases.

- Contractual Enhancements

  - ✓ Bilateral vesting contracts with distribution companies during a transition period.
  - ✓ Bilateral contracts with retailers or retail customers (tolling contracts are a form of this structure).
  - ✓ Contracts with fuel suppliers and/or O&M contractors where operating expense are subordinate to debt service.
  - ✓ Contracts with fuel suppliers where the price of fuel varies in when the price of electricity varies.
  - ✓ Risk hedging through use of forward contracts.
  - ✓ Combination of MPPs in to portfolios to moderate asset concentration.

The manner in which these structural enhancements should impact the ADB's process of underwriting debt for an MPP transaction is described below. In assessing whether to include various enhancements in a transaction and how to price transactions with and without various enhancements, the ADB must be able to value the different structural elements. To value of the different enhancements we evaluate how the financial and contractual mechanisms affect the probability of default and the loss given default of a loan. We begin by measuring the value of financial enhancements and then we describe how to value contractual enhancements.

### 5.7.2 Financial Enhancements and Financial Structuring

Typical MPP transactions allow at some level of dividends to be paid to sponsors from cash flow before all of the debt has been repaid. Furthermore, project financings often have various tranches of debt where cash flow is not applied to subordinated debt unless all of the senior debt service is paid. Various structural techniques can be used to protect the position of senior debt holders relative to other investors including covenants that restrict dividend payments, debt service reserve accounts and inter-creditor agreements between senior and subordinated debt. In developing a debt structure for an MPP, the ADB must assess which type of covenant is most important and whether structuring elements such as cash flow traps are more important than large debt service reserves. Furthermore, if the ADB takes a subordinated position to senior debt, the pricing of the subordinated debt issue relative to the senior debt must be established.

### 5.7.3 Covenants

Loans typically include a set of positive and negative covenants. Positive covenants include terms such as having business insurance, having audited accounts and keeping equipment in good condition. Negative covenants generally include

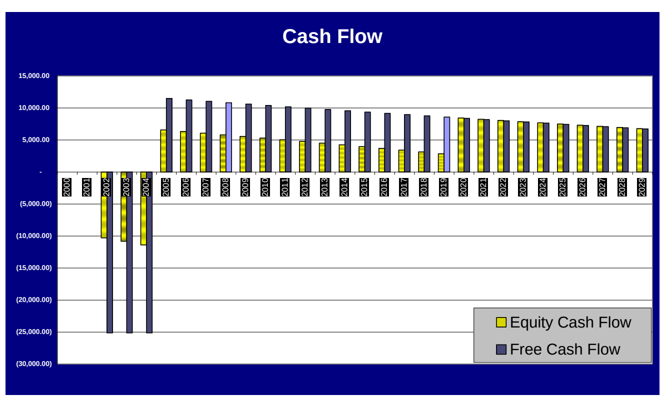
limitations on risky business activities and limitations on issuing additional debt. In addition to typical covenants, an MPP transaction can include controls on cash flows that limit the amount of dividends that can be paid to sponsors. The limitations on cash flows are designed with the debt service coverage ratio.

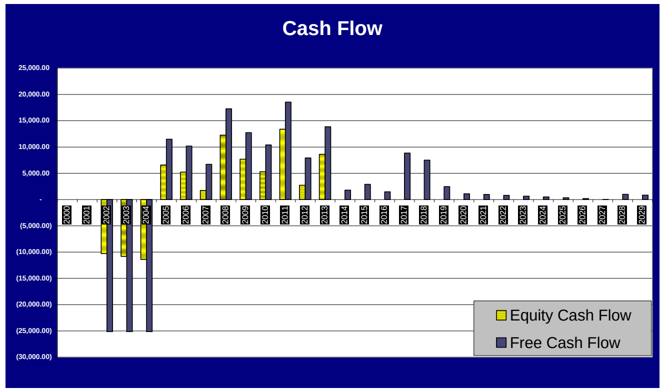
Covenants can restrict the amount of dividends paid to sponsors during good time and bad time periods. Covenants that restrict cash flow in bad time periods are known as cash traps. Covenants that limit cash payments when cash flow is high are known as cash flow sweeps. These covenants are explained as follows by Standard and Poor's:

Standard & Poor's believes that a project's credit is generally strengthened by covenants that limit, or even preclude, distributions to sponsors unless both robust historic and projected DSCRs are met, and reserve funds are fully funded.

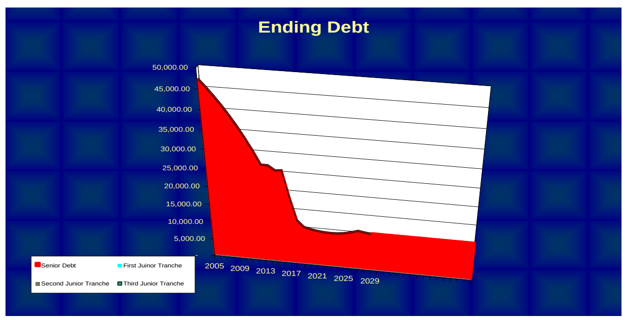
The reason for dividend restrictions in time periods when cash flow is low is because when financial results are worse than expected, it is essential to assure that cash flow is kept for the debt holders and not "leaked" out of the project as dividends. A cash flow trap operates by limiting any dividend payments if the debt service coverage is below a debt service ratio criteria. If the dividend restriction is tied to a relatively high level of the debt service coverage such as 2.5x, the dividend restriction will occur more often than if the dividend restriction is set to a relatively low level such as 1.2x – the "bad" time periods occur more often with the higher covenant. Since the covenant limits dividends, cash flow traps mean that something must be done with the cash flow that is not distributed to sponsors. Cash either can be used to payoff debt early or be put into a debt service reserve to protect debt holders.

The graphs below show how cash flow traps affect cash flows to equity and debt holders. The first graph illustrates cash flow in a situation without price volatility where the spot price follows a downward trend. The bars on the graph represent total cash flow to the MPP project and cash flow received or distributed by equity holders. The second graph shows the cash flows in a situation where prices vary from year to year due to assumed price volatility. In the second graph dividends are paid to shareholders in early years when electricity prices are relatively high while dividends cannot be paid in later years when prices are lower.

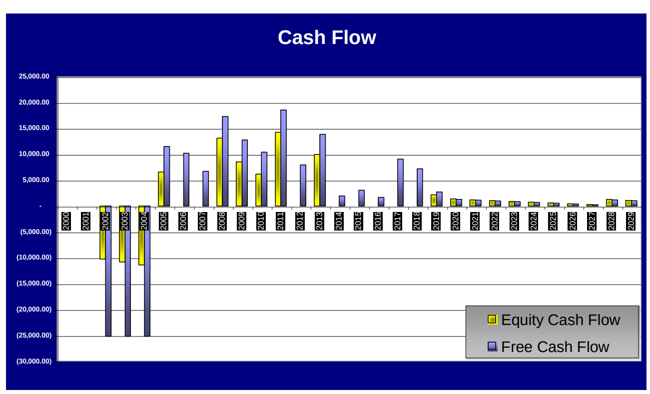





In the scenario with price volatility, the debt cannot be repaid as cash flows are lower in the ending year of the project. Debt is scheduled to be re-paid in these latter years, but it cannot be fully re-paid as shown in the graph below. The graphs imply that dividends were paid to shareholders even though the total debt could not be repaid.



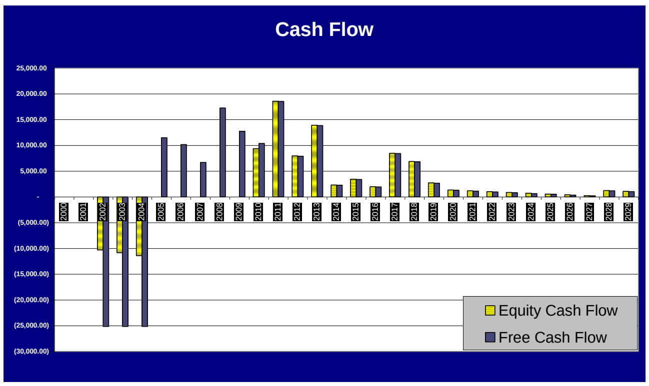

With a covenant that “traps” cash flow and restricts dividends unless the debt service coverage is above 2.0x, the dividends are limited as shown in the graph below. The covenant simply means that any time the debt service coverage is below 2.0x, no dividends can be paid. In years when the cash flow is relatively low – three of the years on the graph below – dividends are not allowed to be paid to shareholders because of the covenant. The cash that would have been paid as dividends is used to re-pay debt early and there is less debt to re-pay at the end of the project life. This limitation on dividends means that the total amount of the debt can be repaid.



If the cash flow trap is more restrictive – the covenant is set to a higher level -- the debt should experience a lower probability of default. A more restrictive covenant implies a lower probability of default. This should also imply that a lower credit spread can be accepted in the pricing of debt. Probability of default and loss given default can be measured by including the cash trap in the project finance model and applying the Monte Carlo simulation with alternative levels of cash trap covenant restrictions. The table below presents the probability of default, the loss given default and the required credit spread for different levels of cash trap covenants assuming price volatility of 25% and debt leverage of 60%. The table demonstrates that if the dividend is restrictive in the sense that dividends are rarely allowed until all of the debt is repaid, the credit spread falls by almost 300 basis points. The reason the probability of default declines by such a large amount is because the highly restrictive covenant essentially means that all debt is repaid before any dividends are allowed.

| | NGCC Plant - 60% | | | |
|---|---|---|---|---|
| | No Dividend Restriction | 1.5 x Divdidend Restriction | 2.0 x Divdidend Restriction | 2.5 x Dividend Restriction |
| **Results** | | | | |
| Credit Pricing | | | | |
| Probability of Default | 31.30% | 25.90% | 19.10% | 12.70% |
| Loss, Given Default | 14.91% | 16.50% | 18.72% | 14.68% |
| Required Credit Spread | 4.67% | 4.27% | 3.58% | 1.86% |

A second type of covenant applies in periods when cash flow is high rather than when cash flow is low. The reason for restrictions on dividends in good time periods is because when prices higher than normal, cash flow can be kept for the debt holders to protect against default in later periods when cash flow and prices may be below normal. Cash flow sweeps operate by computing the amount of dividends that will just limit the debt service coverage to the covenant. Unlike the cash traps, if the cash sweep covenant is set to a low level it is more restrictive (the cash flow trap covenant described above was more restrictive with a higher level). If the cash sweep is tied to a relatively low level of the debt service coverage such as 1.5x, the dividend restriction will occur more often than if the dividend restriction is set to a relatively low level such as 3.5x. The graph below uses the volatile price scenario presented above to illustrate how dividend payments are reduced in a scenario with a covenant that sweeps cash flow. In the scenario with cash flow sweeps, no dividend payments are allowed in the early years until much of the debt is paid off. As with the dividend restriction the covenant, the cash flow sweep allows the debt to be fully paid off because dividends are not “leaked” out of the project to shareholders.



If the cash flow sweep covenant has a lower debt service coverage criteria to limit dividend payments, the debt should experience a lower probability of default. The lower probability of default should also imply that a lower credit spread is appropriate. To measure the effect of cash flow sweeps on the probability of default, we have added cash flow sweeps to the project finance model and assumed that dividend limitations caused by the cash sweep covenant prompt early re-payment of debt. With the cash flow sweep included, the probability of default is measured from Monte Carlo simulation.

The table below demonstrates the probability of default, the loss given default and the required credit spread for different levels of criteria for cash flow sweeps. With a covenant set at 4.0x, the credit spread declines by 100 basis points while with a covenant set at 3.0x, the credit spread declines by more than 200 basis points. These results show that the ADB should include both cash flow sweeps and cash flow traps in MPP transactions. Further, the covenants are more important if electricity prices are more volatile. Both cash flow sweeps and dividend restrictions can be included in an MPP transaction. The summary table at in Section 5.3 above demonstrates application of both a cash flow sweep covenant set to 3.0x and a cash flow trap of 2.0x. These two covenants together reduce the credit spread from 4.67% to 2.93%.

| | NGCC - 60% Leverage | | | |
|---|---|---|---|---|
| | No Cash Flow Sweep | 4.0x Cash Flow Sweep | 3.0x Cash Flow Sweep | 2.0x Cash Flow Sweep |
| Results | | | | |
| Credit Pricing | | | | |
| Probability of Default | 31.30% | 5.50% | 5.00% | 4.30% |
| Loss, Given Default | 14.91% | 66.37% | 68.82% | 60.99% |
| Required Credit Spread | 4.67% | 3.65% | 3.44% | 2.62% |
| | | | | |
| Assumptions | | | | |
| Electricity Price | | | | |
| Price Volatility | 25.00% | 25.00% | 25.00% | 25.00% |
| Price Trend | -1.00% | -1.00% | -1.00% | -1.00% |

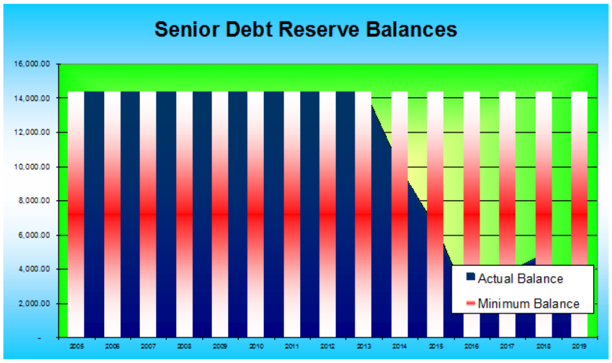
### 5.7.4 Debt Service Reserves

Project finance loans often include a debt service reserve as well as covenants. In project finance transactions with long-term contracts, debt service reserves are typically set at a level that will assure that the next debt service payment can be made. Since debt service typically occurs on a semi-annual basis, the debt service reserve is generally set at a level that can pay six months of debt service (interest plus principal). In this way, the debt service reserve provides liquidity to a project much like the current ratio or the quick ratio is used to assess the liquidity of corporate credits.

In the case of MPPs, higher levels of debt service reserves than the six month rule of thumb, such as debt service reserves that cover 12 months or more of debt service, are often considered more appropriate because of the volatility in market prices. In other words, projects with electricity price risk should have reserve accounts to provide sufficient liquidity to ensure that temporary financial problems driven by low prices that may occur for a year or more do not force a default. This means that reserve levels should reflect the historical and projected commodity price volatility. Standard and Poor’s for example suggests that peaking power projects with should

have 12 to 18 months' debt service reserve funds. While debt service reserves protect the position of lenders, the debt service reserves are expensive from the perspective of sponsors because more capital must be raised for the project and because the interest rate earned on funds in a debt service reserve is very low compared to the expected return earned on the project.

The graph below illustrates how a debt service reserve can protect lenders to an MPP project. With a high level of a debt reserve, when cash flow is insufficient to pay debt service, the cash flow is used to put money back into the debt service reserve. If the debt service reserve has been used to pay meet debt service obligations in an earlier year and it is not at its required level, the debt service reserve must be replenished before debt can be repaid. This means that when cash flow is positive, cash must be used to replenish the reserve instead of flowing to equity holders as dividends. In the scenario used to develop the graph, without the debt service reserve, the cash flow would not have been sufficient to pay off the debt. With the debt service reserve, the debt can be fully repaid.




### 5.7.5 Senior and Subordinated Debt

An important ADB product in assisting the development of MPPs in Asia may be subordinated debt or junior debt offerings that have a longer term than senior debt. With subordinated debt in the capital structure of an MPP, the cash flow first pays all of the debt service on a senior debt issue and only the remainder is used for junior debt. Because use of subordinated debt in an MPP capital structure means that senior debt service is lowered, the existence of subordinated debt improves the credit quality of the senior debt. Given the reluctance of financial institutions to finance MPP debt after financial problems that have occurred in the industry, ADB subordinated debt issued for an MPP project could be the difference between projects being developed and not being developed. From the perspective of senior debt holders, a subordinated debt strategy may partially mitigate commodity electricity market risk, either initially or after a bilateral contract expires when a project faces electricity price market risk. If subordinated debt is used in an MPP transaction, an inter-creditor agreement must be established that carefully defines restrictions on the payment of subordinated debt service to protect the senior debt holders. Use of subordinated debt is illustrated in the table below. Note that the senior debt service coverage improves while the junior debt service coverage is lower than the senior debt service coverage.

| Debt Parameters and Outputs by Tranche | Senior | Junior 1 |
|---|---|---|
| Average DSCR | 2.62 | 1.99 |
| Minimum DSCR | 2.11 | 1.38 |
| LLCR | 3.15 | 4.48 |
| Interest Rate | 8.5% | 10.0% |
| Percent of Permanent Debt Financing | 70.0% | 30.0% |
| Debt Service Reserve Percent | 0.0% | 0.0% |
| Good Time Pre-payment DSCR | 3.00 | 2.00 |
| Bad Time Pre-payment DSCR | 2.00 | 1.00 |
| Ending Debt - Term | - | - |
| Ending Debt - Life | - | - |
| IRR on Debt | 8.50% | 10.00% |
| Initial Debt | 109,735 | 47,029 |

If the ADB finances subordinated debt it will not be able to require payment without prior senior debt holder approval. Such debt must be deeply subordinated to senior debt with severely limited rights of acceleration or access to project collateral. Repayment of such subordinated debt should be well below other cash claims, falling just ahead of equity dividends. While subordinated debt can support MPP development, underwriting subordinated debt and establishing the credit spread for subordinated debt is a complex process.

The pricing of subordinated debt can be assessed in a similar manner as the process described above for a single debt issue. To measure the probability of default and the loss given default for subordinated debt, the project finance model is structured with a cash flow waterfall to measure the amount of subordinated debt and senior debt that remains at the end of the life of the project. Once the project finance model includes a cash flow waterfall, the probability of loss and the loss given default can be assessed with Monte Carlo simulation. The table below illustrates the required credit spread, the probability of loss and the loss given default for both senior and subordinated debt assuming different levels of senior and junior debt. We present two scenarios with junior debt – one with a junior debt issue that comprises 30% of the total debt and another where the junior debt issue is 50% of the total debt. In all cases, the total senior and junior debt together represents 60% of the total cost of the project. The table demonstrates that use of junior debt dramatically reduces the risk of the senior debt – to the point at which if 50% of the debt is subordinated, the required credit spread for senior debt is below .5%. Of course, the required credit spread and the risk of the junior debt exceeds the credit spread of the senior debt. The analysis of subordinated debt in the table below demonstrates that the ADB can use junior debt as a tool to attract capital to an MPP. However, if the ADB uses junior debt as a tool, the pricing must reflect the additional risk.

| | NGCC - 60% Total Leverage | | |
|---|---|---|---|
| | 100% Senior Debt | 70% Senior / 30% Junior | 50% Senior / 50% Junior |
| Results | | | |
| Credit Pricing - Senior | | | |
| Probability of Default | 31.30% | 2.00% | 0.60% |
| Loss, Given Default | 14.91% | 63.32% | 59.99% |
| Required Credit Spread | 4.67% | 1.27% | 0.36% |
| Credit Pricing - Junior | | | |
| Probability of Default | NA | 10.30% | 7.16% |
| Loss, Given Default | NA | 60.47% | 32.24% |
| Required Credit Spread | NA | 6.23% | 7.16% |

The above analysis of covenants, debt service reserves and subordinated debt illustrates that the process for evaluating financial enhancements that mitigate or allocate risk is complex. The risks can be gauged using a mathematical process that incorporates the volatility of electricity prices. However, even if the mathematical techniques are not applied in practice, the conceptual points demonstrated by use of the complex approach should be included by the ADB in its credit analysis process to underwrite MPP transactions.

### 5.7.6 Contractual Enhancements and MPP Credit Analysis

The financial structuring enhancements discussed above can mitigate risk by allocating cash flow available to the MPP to various classes of debt and equity investors. In addition to covenants, debt service reserves and subordinated debt, contractual enhancements such as bilateral contracts can mitigate MPP risk. Unlike the case of covenants, debt service reserves and subordinated debt, risk is not simply allocated between equity holders and debt holders. Instead, in the case of using contracts to mitigate risk, cash flow risk is allocated to parties who do not invest in the MPP. The most commonly discussed way to mitigate risk through contracts is through bilateral long-term contracts with power purchasers. Other ways to use contracts to mitigate risk of an MPP include supply contracts that are subordinate to debt service, supply contracts structured so the fuel price varies when the electricity price varies and use of forward markets to mitigate revenue risk.

The remainder of this section describes how the various contractual enhancements affect the underwriting of ADB debt and the credit spread that is appropriate for MPP transactions. We begin by assessing how bilateral purchase contracts affect risk and then move to supply contracts and risk hedging. The process of valuing the credit aspects of the contractual enhancements applies the probability of default and the loss given default approach discussed above.

### 5.7.7 Risk Mitigation with Bilateral Revenue Contracts

An MPP was defined in Part 1 as a plant that can have a bilateral contract. The plant was defined as an MPP as long as the contract between the MPP and the off-taker is subject to commercial risk. This means that a plant which signs a contract with a retail customer who can purchase from the market; a plant that signs a contract with a retailer subject to market competition in dealing with retail customers; a plant that signs a contract with a marketer who sells power in wholesale markets using a tolling agreement; or a plant that signs a contract with a distributor that is subject to retail choice are all defined as merchant plants. Finally, a plant that signs a vesting contract with a distribution company which is government owned or government regulated and has non-contestable customers is considered a hybrid MPP.

This section discusses how bilateral contracts can mitigate risk of ADB MPP transactions. We first describe the nature of bilateral contracts and then discuss how these contracts affect the ADB underwriting process and the pricing of ADB debt instruments. In addition to mitigating risks for individual MPP transactions, bilateral contracts raise a number of important policy issues in the context of developing a market framework. Bilateral contracts can lower the cost of capital to MPPs and moderate price volatility in a market. However, vesting bilateral contracts can also defeat some incentives to purchase and supply electric power in an economically efficient manner. Quantification of these policy issues associated with bilateral

contracts including the cost of capital are addressed in Section 5.8 below.

Until recently, MPPs that sold power much of their power at spot market prices were considered more attractive than plants that had all of their power sold under bilateral contracts. For example, MPPs in the US often received commitments for only 40-65 percent of their power sales. The idea was that the remainder of the power would be sold at market rates and receive higher spot market prices. The notion of receiving higher profit from selling spot power fell apart in the US as natural gas prices increased and as wholesale electricity prices fell because of declines in demand and too much generation supply. Given changes in the market, merchant companies that attempted to sell significant power at spot prices have realized profit margins which are so thin that many have had trouble covering their fixed costs.

If an MPP has a bilateral contact such as a tolling agreement or a long-term contract for difference with a retailer, market risks can be mitigated and higher debt leverage can be obtained. In terms of risk allocation, bilateral contracts are similar to power purchase agreements in that they provide a stable stream of cash flow in the form of contractually based revenues. In some cases the risks that remain with the MPP after signing a bilateral contract with a marketer or with a retailer are less severe than those remaining under a power purchase agreement with a utility. For example, typical tolling arrangements imply that the risks assumed by the MPP sponsor are limited only to the availability of the plant and the plant efficiency.

In underwriting transactions that include bilateral contracts, the ADB must assess the market price risks that remain once the bilateral transaction expires and the risks that the counterparty to the bilateral contact will not be able to meet obligations of the contract. The creditworthiness of utility company off takers can generally be captured in the utility's corporate credit rating. In traditional IPP/PPA transactions the bond rating of the off taker often did not cause problems in terms of underwriting the loans. For example, because the average utility rating was often in the A category, the project debt was typically rated BBB. On the other hand, off takers for MPPs are generally retail customers, retailers, or energy marketing and trading companies. These companies either have lower credit rating or do not have a credit rating. To compound the problem, off takers will be most likely to default when the bilateral contract is out of the market and the MPP will not be able to make up lost revenues from the contract through making spot market sales. The case study of AES Drax discussed in Part 3 highlights this problem.

To quantify the effect of bilateral contracts for purposes of underwriting and determining credit spreads, we describe two approaches below. The first method involves break-even analysis to determine the minimum price at which power can be sold and debt can be serviced. This break-even technique can establish the level of market prices for different amounts of debt leverage and different bilateral contract terms. The second method applies the Monte Carlo simulation technique to measure the probability of loss and the loss given default assuming different bilateral contract terms. This method can incorporate the credit quality of off-takers as well as the volatility of market prices.

The break-even approach is illustrated for evaluating the risk mitigating effects of bilateral contracts is shown in the series of tables below. These tables present the break-even price for different assumed leverage levels and for different contract assumptions. Pricing in the contract is driven by assuming the contract price is $4/MWH below the expected spot price. We apply three different assumptions with respect to contract levels in the case study. The first scenario assumes no contracts,

the second scenario assumes 50% of the plant is contracted for 7 years and the third scenario assumes 100% of the power is contracted for 10 years. For each of the contract scenarios, we measure the lowest amount the market price can be and still meet debt service obligations.

The ability to meet debt service obligations using break-even prices is measured using two alternative approaches. The first approach measures the break-even price by determining how low the market price can be and still maintain a minimum debt service coverage above 1.0. The second approach measures the minimum market price that can be achieved and assure that no debt is outstanding at the end of the life of the project. The break-even analysis is shown for the NGCC plant, the coal plant and the CT plant in the three tables below. The table shows that the coal plant has the most margin for a lower price because its capital base – the debt service and dividends are higher than for the less capital intensive plants. The tables also illustrate how contracts equate to a higher level of leverage. For a certain acceptable break-even price, the risks can be mitigated either through a contract or through lower levels of leverage. In the case of an NGCC plant, a level of leverage of 45% with no contact is approximately the same as 75% leverage with a 10 year bilateral contract. The analysis makes it clear that ADB products which support contracts such as risk insurance on the contract are important from the perspective of MPP developers.

**Coal Plant**

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| Base Spot Price | $ 39.00 | | | | | | |
| Base Contract Price | $ 35.00 | | | | | | |
| | **No Bilateral Contract** | | | | | | |
| Debt Leverage | 45.0% | 50.0% | 55.0% | 60.0% | 65.0% | 70.0% | 75.0% |
| Minimum Debt Service Criteria | | | | | | | |
| Break-even Price in $/MWH | $ 21.80 | $ 22.50 | $ 23.10 | $ 23.80 | $ 24.50 | $ 25.20 | $ 25.90 |
| Percent of Base Case | 56% | 58% | 59% | 61% | 63% | 65% | 66% |
| Money Loss on Debt Criteria | | | | | | | |
| Break-even Price in $/MWH | $ 19.10 | $ 19.60 | $ 20.10 | $ 20.60 | $ 21.10 | $ 21.60 | $ 22.10 |
| Percent of Base Case | 49% | 50% | 52% | 53% | 54% | 55% | 57% |
| | **50% of Power Contracted for 7 Years** | | | | | | |
| Minimum Debt Service Criteria | | | | | | | |
| Break-even Price in $/MWH | $ 20.30 | $ 20.90 | $ 21.60 | $ 22.20 | $ 22.80 | $ 23.50 | $ 24.10 |
| Percent of Base Case | 52% | 54% | 55% | 57% | 58% | 60% | 62% |
| Money Loss on Debt Criteria | | | | | | | |
| Break-even Price in $/MWH | $ 17.20 | $ 17.60 | $ 17.90 | $ 18.30 | $ 18.70 | $ 19.10 | $ 19.40 |
| Percent of Base Case | 44% | 45% | 46% | 47% | 48% | 49% | 50% |
| | **100% of Power Contracted for 10 Years** | | | | | | |
| Minimum Debt Service Criteria | | | | | | | |
| Break-even Price in $/MWH | $ 19.70 | $ 20.30 | $ 20.90 | $ 21.50 | $ 22.10 | $ 22.90 | $ 23.60 |
| Percent of Base Case | 51% | 52% | 54% | 55% | 57% | 59% | 61% |
| Money Loss on Debt Criteria | | | | | | | |
| Break-even Price in $/MWH | $ 16.20 | $ 16.40 | $ 16.70 | $ 17.00 | $ 17.20 | $ 17.50 | $ 17.80 |
| Percent of Base Case | 42% | 42% | 43% | 44% | 44% | 45% | 46% |

## NGCC Plant

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| Base Spot Price | $ 39.00 | | | | | | |
| Base Contract Price | $ 35.00 | | | | | | |
| | **No Bilateral Contract** | | | | | | |
| Debt Leverage | 45.0% | 50.0% | 55.0% | 60.0% | 65.0% | 70.0% | 75.0% |
| Minimum Debt Service Criteria | | | | | | | |
| Break-even Price in $/MWH | $ 29.20 | $ 30.00 | $ 30.80 | $ 31.60 | $ 32.50 | $ 33.30 | $ 34.10 |
| Percent of Base Case | 75% | 77% | 79% | 81% | 83% | 85% | 87% |
| Money Loss on Debt Criteria | | | | | | | |
| Break-even Price in $/MWH | $ 25.80 | $ 26.40 | $ 27.00 | $ 27.60 | $ 28.20 | $ 28.80 | $ 29.40 |
| Percent of Base Case | 66% | 68% | 69% | 71% | 72% | 74% | 75% |
| | **50% of Power Contracted for 7 Years** | | | | | | |
| Minimum Debt Service Criteria | | | | | | | |
| Break-even Price in $/MWH | $ 27.30 | $ 28.00 | $ 28.80 | $ 29.50 | $ 30.30 | $ 31.70 | $ 33.30 |
| Percent of Base Case | 70% | 72% | 74% | 76% | 78% | 81% | 85% |
| Money Loss on Debt Criteria | | | | | | | |
| Break-even Price in $/MWH | $ 23.30 | $ 23.80 | $ 24.50 | $ 25.30 | $ 26.10 | $ 26.90 | $ 27.70 |
| Percent of Base Case | 60% | 61% | 63% | 65% | 67% | 69% | 71% |
| | **100% of Power Contracted for 10 Years** | | | | | | |
| Minimum Debt Service Criteria | | | | | | | |
| Break-even Price in $/MWH | $ 26.50 | $ 27.20 | $ 28.00 | $ 28.90 | $ 29.80 | $ 30.70 | $ 31.60 |
| Percent of Base Case | 68% | 70% | 72% | 74% | 76% | 79% | 81% |
| Money Loss on Debt Criteria | | | | | | | |
| Break-even Price in $/MWH | $ 22.00 | $ 22.30 | $ 22.70 | $ 23.00 | $ 23.30 | $ 23.70 | $ 24.00 |
| Percent of Base Case | 56% | 57% | 58% | 59% | 60% | 61% | 62% |

## Combustion Turbine Plant

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| Base Spot Price | $ 39.00 | | | | | | |
| Base Contract Price | $ 35.00 | | | | | | |
| | **No Bilateral Contract** | | | | | | |
| Debt Leverage | 45.0% | 50.0% | 55.0% | 60.0% | 65.0% | 70.0% | 75.0% |
| Minimum Debt Service Criteria | | | | | | | |
| Break-even Price in $/MWH | $ 21.80 | $ 22.50 | $ 23.10 | $ 23.80 | $ 24.50 | $ 25.20 | $ 25.90 |
| Percent of Base Case | 56% | 58% | 59% | 61% | 63% | 65% | 66% |
| Money Loss on Debt Criteria | | | | | | | |
| Break-even Price in $/MWH | $ 19.10 | $ 19.60 | $ 20.10 | $ 20.60 | $ 21.10 | $ 21.60 | $ 22.10 |
| Percent of Base Case | 49% | 50% | 52% | 53% | 54% | 55% | 57% |
| | **50% of Power Contracted for 7 Years** | | | | | | |
| Minimum Debt Service Criteria | | | | | | | |
| Break-even Price in $/MWH | $ 20.30 | $ 20.90 | $ 21.60 | $ 22.20 | $ 22.80 | $ 23.50 | $ 24.10 |
| Percent of Base Case | 52% | 54% | 55% | 57% | 58% | 60% | 62% |
| Money Loss on Debt Criteria | | | | | | | |
| Break-even Price in $/MWH | $ 17.20 | $ 17.60 | $ 17.90 | $ 18.30 | $ 18.70 | $ 19.10 | $ 19.40 |
| Percent of Base Case | 44% | 45% | 46% | 47% | 48% | 49% | 50% |
| | **100% of Power Contracted for 10 Years** | | | | | | |
| Minimum Debt Service Criteria | | | | | | | |
| Break-even Price in $/MWH | $ 19.70 | $ 20.30 | $ 20.90 | $ 21.50 | $ 22.10 | $ 22.90 | $ 23.60 |
| Percent of Base Case | 51% | 52% | 54% | 55% | 57% | 59% | 61% |
| Money Loss on Debt Criteria | | | | | | | |
| Break-even Price in $/MWH | $ 16.20 | $ 16.40 | $ 16.70 | $ 17.00 | $ 17.20 | $ 17.50 | $ 17.80 |
| Percent of Base Case | 42% | 42% | 43% | 44% | 44% | 45% | 46% |

The Monte Carlo simulation approach for evaluating the risk effects of bilateral contracts is shown in the table below where the probability of loss and the loss given default is applied to different bilateral contract assumptions. In this analysis, three different contract cases are assumed. Unlike the break-even analysis, the Monte Carlo approach can be used to directly assess how the bilateral contract affects required credit spreads. The approach can also incorporate the probability of default inherent in the power contract. In the table below, the contract is assumed to default 10% of the time if the market price is below the contract level.

Data in the table demonstrates the importance of bilateral contracts to the underwriting process of an MPP. With a 5 year contract that only covers 50% of the generation of an MPP the required credit spread is reduced by almost 250 basis points. With a 10 year contract that covers all of the plant output, the credit spread declines to only .76%. These risks are reduced despite lower returns for the project that result from the contract price being below the expected spot price. The credit benefits of bilateral contracts shown in the table below demonstrate that ADB facilitation of bilateral contracts can be instrumental in development of the MPP industry.

| | NGCC - 60% Leverage | | |
|---|---|---|---|
| | No Contract | 5 Year Contract for 50% of Output | 10 Year Contract for 100% |
| **Results** | | | |
| Credit Pricing | | | |
| Probability of Default | 31.30% | 4.00% | 2.10% |
| Loss, Given Default | 14.91% | 54.87% | 36.04% |
| Required Credit Spread | 4.67% | 2.19% | 0.76% |
| DSCR | | | |
| Average DSCR | 1.82 | 1.66 | 1.19 |
| Minimum DSCR | 1.45 | 1.45 | 1.00 |
| IRR | | | |
| Equity | 14.78% | 11.35% | 10.05% |
| Project | 11.09% | 9.50% | 8.20% |
| **Assumptions** | | | |
| Electricity Price | | | |
| Price Volatility | 25.00% | 25.00% | 25.00% |
| Price Trend | -1.00% | -1.00% | -1.00% |

### 5.7.8 Risk Absorption from Suppliers

Power plants that had long-term contracts fixed the level of revenue and many other items. If revenues are fixed, then operating and maintenance costs, fuel expenses, interest expenses and other items should also be fixed. In the case of an MPP, revenue is not fixed, and cash flow risk can be moderated if expenses vary in the same direction as revenues. For example if fuel expense declines when prices decline, cash flow risk will be reduced. An example of costs varying in the same direction as revenues is Fuel Supply subordination. The fuel subordination in an MPP can take various forms. In the extreme, fuel is supplied to the plant at no cost when the electricity price is low. In less extreme cases, the price of fuel is reduced when the electricity price is low.

The following quote from Fitch Investor Services illustrates fuel subordination for a gas-fired merchant plant in the Northeast US (the Digton Power Plant):

> A significant credit factor in the transaction is the enhancement offered by the

subordination of the natural gas commodity costs to the senior debt service payments. As part of the long-term fuel supply arrangement with an investment-grade supplier, the supplier was willing to subordinate moneys received to non-fuel operating expenses, reserves, and senior debt service over the life of the bonds. This subordination constitutes a form of quasi-equity.

In MPP transactions involving fuel intensive plants such as oil plants or gas plants, the use of fuel supply contracts that moderate risk is equivalent to the lower price volatility. The ADB should encourage the use of fuel subordination agreements in underwriting credit and should facilitate the contracts by offering insurance for the contracts.

### 5.7.9 Hedging of Market Risks through Forward Contracts

As stated in Part 3 of the report, one of the most important aspects of developing a market framework is assuring that a forward market exists by which prices can be hedged. With liquid forward markets, it is possible to hedge both the price and the volume of dispatch risk of MPPs. The manner in which risks can be hedged using forward markets is illustrated by considering a natural gas combined cycle plant. Through use of options markets for both natural gas and electricity, the price and volume risks can be fully hedged. Assume the gas price is $3/MMBTU and the heat rate is 10,000 BTU/kWh and there is no variable O&M expense then the variable cost of the plant is $30/MWH. When the electricity price is above $30/MWH the plant is dispatched and a margin of the electricity price minus $30/MWH is earned. The plant earns cash flows if the electricity price is above $30/MWH and it makes cash outflows to pay for the cost of gas. A series of option contracts on natural gas prices and electricity prices can be structured to fully hedge both the volume and price risk of the plant. The problem with this type of hedging strategy is that forward contracts do not exist for terms that correspond to debt tenors. Therefore, the remaining merchant must be established in a similar manner to the contract case discussed above. Appendix 5 addresses some technical aspects of hedging the risk of MPPs.

## 5.8 Analytical Models to Evaluate Policy Issues Associated with Market Frameworks

### 5.8.1 Analytical Models and ADB Strategy Reports

The ADB Staff formulates five year strategies for reform of sectors in developing nations that encourage sustainable and efficient development. These strategic plans include a “wish list” for what the country should do in the generation sector regarding transparent contracting, efficient pricing, encouraging reliable supply, limiting monopolist behaviour by private developers and other policies that promote sustainable development. One of the reasons for developing the roadmap for a market framework described in Section 5.1 was to guide the ADB Staff in developing these strategic reports. Many of the recommendations included in the above roadmap describe essential elements of a market framework that clearly should be put in place to support MPP development. For example, we recommended that distribution, generation and transmission should be unbundled; that market mechanisms must be established with equal access to transmission; that privatisation should not create market power; that spot prices should be published, and that forward markets should be established which allow merchant plants to hedge market

risks. These recommendations are “home truths” that need not be analysed or quantified with modelling analysis.

Another set of recommendations relates to open issues involving market implementation and the required MPP framework. These issues include:

1) do the benefits from bilateral contracts from the standpoint of attracting merchant capacity off-set the costs of bilateral contracts on optimal market behaviour;

2) do the benefits of price caps in terms of limiting market power offset economic distortions in the market;

3) do the benefits of a cost-based energy market in terms of limiting market power offset the lack of economic incentives and the administrative capacity price mechanisms that are required in a cost based system; and

4) what type of capacity pricing system should be implemented to attract merchant capacity and limit the exercise of market power.

Price forecasts using simulation models are presented below to evaluate impacts of policy alternatives available to developing countries and risks faced by the ADB as an investor in merchant power plants. For example, price forecasts using forward price simulation models evaluate how various capacity pricing structures affect long-term price levels, price volatility, the reliability of electricity supply, and the amount and mix of capacity in the long-term. To analyse policy with respect to a capacity pricing framework, we have used a common set of assumptions with respect to loads, the cost of new capacity, fuel prices and other variables. The analyses presented below are evaluated assuming different policies with respect to price caps, different administrative determinations of reserve margin, value of lost load (“VOLL”), and different behaviour of private developers.

### 5.8.2 Use of Forward Price Simulation Models to Evaluate Policy Issues

Long-term forward price models introduced above in Section 5.4 can be used to evaluate whether policies included in a market framework will be beneficial for people and businesses of developing countries as well as to support MPP investment analysis. To illustrate how modelling can be used in policy analysis, consider how a developing country should decide upon the best design of a market structure for capacity prices. As discussed in Part 3, alternative market designs with respect to capacity pricing include:

1) Bid-based systems with an energy only price and no price caps or price caps sufficiently high to support peaking and reserve capacity, such as the systems used in Australia and Nordpool;

2) Separate installed capacity markets that have been implemented in PJM and the New York Pool in the US;

3) Administratively determined capacity support such as the method used in South Korea and Columbia; and

4) Application of a uplift to energy prices such as adding the value of lost load (“VOLL”) to energy charges that is dependent on loss of load probability

("LOLP") such as the market originally used in the UK and the system in place in Argentina.

In assessing which market design is best for a particular country, policy makers must address a number of issues in deciding on the appropriate market structure. Four issues include assuring that markets will: (1) provide reliable electricity to consumers; (2) be sustainable in the long-run through attracting capacity from private developers; (3) result in prices that are not extremely volatile; and, (4) minimize the potential of generating companies to exercise market power.

To illustrate how analytical models can be used to evaluate tradeoffs inherent in various policy questions, the table below summarizes customer costs in a simulation model using different scenarios with respect to capacity pricing and market power. The details of various numbers in the table are presented in the paragraphs below. The measurement uses index numbers where geared to an ideal perfect market with no market power and no government interference. The first row shows customer costs that would occur in a pure optimal scenario without market power and with an ideal bid-based capacity pricing system. The second and third rows show the increased prices that can result from exercise of market power at times of high prices. These rows illustrate that the ideals of a market system can be evaporated if private companies can exercise market power. The fourth and fifth rows illustrate the effects of different levels of price caps – a cap of $1,500/MWH and $300/MWH -- implemented to moderate market power.  The analysis depends on many assumptions and analytical techniques that are described below in Section 5.9.

| | Long-term Prices | | | Reliability | | | Capacity Mix | | |
|---|---|---|---|---|---|---|---|---|---|
| | Equilibrium Price | Total Cost incl VOLL | Price Volatility | Loss of Load Probability | Cost of Lost Load | Reserve Margin | Peaking Capacity | NGCC Capacity | Coal Capacity |
| **Energy-Only Markets** | | | | | | | | | |
| Without Price Caps | $ 38.80 | 1.00 | 27% | 0.0274% | 1.00 | 8.50% | 40% | 20% | 40% |
| With Market Power | $ 45.78 | 1.17 | 33% | 0.1142% | 0.97 | 12.00% | 37% | 39% | 24% |
| Price Cap of $500/MWH | $ 43.07 | 1.10 | 24% | 0.1027% | 1.09 | 7.20% | 28% | 35% | 37% |
| Price Cap of $250/MWH | $ 43.93 | 1.12 | 25% | 0.1007% | 1.10 | 7.00% | 26% | 36% | 38% |
| **Installed Capacity Markets** | | | | | | | | | |
| Reserve Margin of 15% | $ 41.50 | 1.07 | 20% | 0.0206% | 0.92 | 15.00% | 45% | 32% | 23% |
| Reserve Margin of 20% | $ 43.16 | 1.11 | 17% | 0.0171% | 0.89 | 20.00% | 47% | 25% | 28% |
| Reserve Margin of 30% | $ 44.89 | 1.16 | 15% | 0.0137% | 0.82 | 30.00% | 50% | 24% | 26% |
| **Administrative VOLL Markets** | | | | | | | | | |
| VOLL of $1,000/MWH | $ 42.52 | 1.10 | 24% | 0.0206% | 0.92 | 15.00% | 45% | 31% | 24% |
| VOLL of $2,500/MWH | $ 41.69 | 1.07 | 26% | 0.0243% | 0.96 | 11.85% | 42% | 27% | 32% |
| VOLL of $7,500/MWH | $ 39.70 | 1.02 | 28% | 0.0279% | 0.99 | 8.70% | 39% | 22% | 39% |

The above table does not answer the question of whether price caps should be put in place to address market power considerations. Rather, the analysis illustrates how the ADB can use technical assistance tools presented in this part of the report to illustrate the possible impacts and tradeoffs inherent in alternative policy options. The implication of the above table is that the ADB can perform analyses that quantify the effects of different market designs.

### 5.8.3 Policy Analysis, MPP Cost of Capital and Bilateral Contracts

Part 3 of the MPP report described how policies implemented in creating a framework for market generation can affect the willingness of MPPs to make investments in a country. The manner in which a framework affects promotion of MPPs can be quantified in terms of the cost of capital and the carrying charge. As described in Part 3 of the MPP report, there has been a major change in the attitude of financiers to

MPP investments that make financing new MPPs more difficult. The increased difficulty in obtaining financing is quantified below by measuring the cost of capital before and after the "financial meltdown."

The relationship between cost of capital and debt structure can be illustrated by considering a hypothetical decision making process in the financial analysis department of an energy company. Begin with the notion that management has a rate of return criteria where only projects that have an IRR of above 14% are approved for investment and projects that have an IRR below 14% are not. Further, assume that this rate of return is measured using equity cash flow rather than free cash flow, due to corporate objectives related to earnings per share ("EPS") growth. In this hypothetical situation as long as free cash flow from the project is expected to yield a higher rate of return (project IRR) than the after tax cost of debt, the equity return can be increased if more debt is used to finance the asset. (Magnifying asset returns to increase equity return is the where the term leverage comes from). If, because of the reluctance of bankers to take credit risk, debt cannot be raised for the project, the equity return criteria will probably not be met. On the other hand, if a significant amount of project debt can be raised, the equity IRR will exceed 14% and the investment will be made. Therefore, in this hypothetical example the amount of debt directly affects the investment decision. Indeed, the investment is driven by the amount of debt that can be raised rather than by the beta of the project or the risk adjusted all-equity cost of capital relative to the project IRR.

The notion that the leverage of a project affects cost of capital is demonstrated in the following quote from a rating agency:

> Nonetheless, a project's leverage level is often an indication of its creditworthiness. For instance, a merchant project's ability to produce a stable and predictable revenue stream will never match that of a traditional contract revenue-driven project. Projects with merchant exposure may find that leverage cannot exceed 50% if investment-grade rated debt is sought. Contract-revenue driven projects, on the other hand, typically have had leverage levels around 70% to 80%.

### 5.8.4 Policy Analysis, MPP Cost of Capital and Bilateral Contracts

This section describes how the environment surrounding a market framework affects the cost of capital, the carrying charges and the investment activity of merchant plant developers. The carrying charge for a merchant plant which includes required equity returns, debt service payments and income taxes affects the long-run marginal cost and the forward pricing models. Carrying charges therefore can be used to quantify how policies that change the cost of capital affect electricity prices required before investors will install capacity.

Measurement of the cost of capital and carrying charges can be used to quantify how policy alternatives that encourage MPP development such as promoting bilateral contracts and assuring financially stable off-takers affect the cost of electricity to consumers. Bilateral contracts lower the cost of capital for merchant plants and should attract more capacity and lower electricity prices. To demonstrate how cost of capital is affected by the financial and market environment we quantify how changes in the cost of capital impacts electricity prices.

The analysis below illustrates how changes in the ability of merchant developers to

raise money affect consumer costs in a competitive market. To illustrate this, three scenarios are developed to represent financing conditions facing merchant developers in the recent past. The first case applies aggressive financing that occurred in the UK in the late 1990's. Many of these plants were able to realize debt to capital ratios of more than 80% with debt tenors exceeding 20 years and with interest rates of about 1.5% above the LIBOR rate. We assume that investors that investors require a 15% equity return (the equity IRR) in order to make an investment. These financing characteristics are applied to the combined cycle and the coal plant characteristics described in Section 5.3.

The second case applies a more typical merchant financing which assumes a debt to capital ratio of 60%, a debt tenor of 15 years and an interest rate spread of 2.0%. This case also assumes a required rate of return of 16%. This financial structure is typical of merchant plants that have been financed in the past.

The financing structure applied to merchant power development in the 1990s is generally considered to be too aggressive relative to risks that are inherent with competitive electricity. For example, in the US, private companies that own merchant plants have lost of more than $100 billion in market capitalization since 2002. In 2003, three very large companies in the merchant power industry -- NRG Energy, Mirant and Pacific Gas & Electric's unregulated generation subsidiary -- filed for bankruptcy. Because of these financial failures there is a consensus that future financing will be far more conservative. Four examples of recent commentary by financiers are listed below:

- "While competitive power fundamentals may never point to great business, firms in other industries can survive under similar circumstances and may even do well, but they do so under much more conservatively financed structures than many energy merchants first envisioned,"

- Banks are "now highly reluctant to take merchant risk of any kind… and they are sceptical about long-term purchase or tolling contracts that in any are considered to be out of the money."

- Merchant risk is usually BB risk – junk bond status -- at most unless it benefits from a very conservative finance structure.

- Merchants will have to redesign their business models. Those players that have 80-90 percent of their capital in the form of debt won't survive. The ratings agencies have said that such debt-to-capital ratios must be in the 50-50 range to earn investment grade status so that the cost of borrowing is reasonable.

To model the impacts of a conservative capital structure, we assume a 50-50 capital structure, a debt tenor of 10 years and a credit spread reflective of below investment grade bonds of 3.5%. Given the problems with losses on plants, we assume that investors in the future require a 17% equity return. As compared to the aggressive financing realized in the past, investors would have to expect higher electricity prices before making an investment with this financing structure.

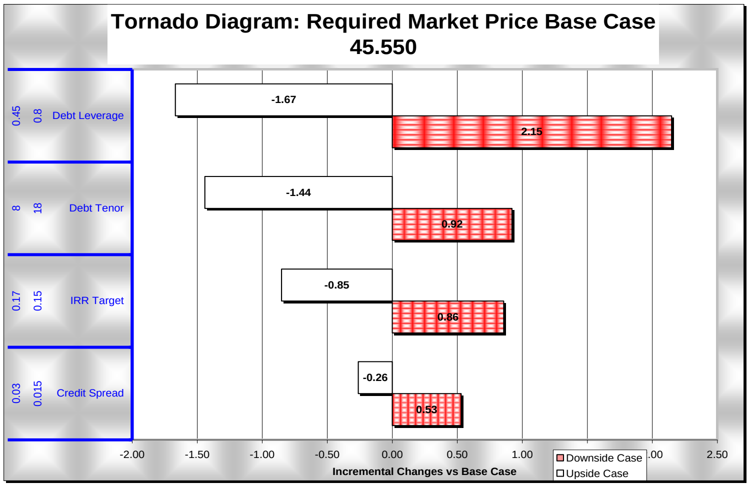
The two tables below illustrate how differences in the financial structure of MPPs affect the average annual price required for an MPP plant. The first table shows

results for the combined cycle plant and the second table shows results for the coal plant. The tables demonstrate how an aggressive financing structure representative of UK MPPs results in a required market price of $29/MWH for the combined cycle plant while the typical MPP financing structure prior to the financial meltdown results in a price of $32/MWH. The conservative financing structure reflective of current conditions results in a price of $35/MWH. This means that the worse conditions surrounding the financing of MPPs should increase costs to consumers in the long run by 22% if only NGCC plants existed in the market. For the coal plant case, the financing cost of MPPs increases by 25% due to the worse financial environment.

| NGCC Plant | Aggressive Financing | Historic Financing | Conservative Financing |
|---|---|---|---|
| Assumptions | | | |
| Debt Leverage | 80% | 65% | 50% |
| Debt Tenor | 20 | 15 | 10 |
| Credit Spread | 1.50% | 2.00% | 3.50% |
| Equity IRR Required | 15% | 16% | 17% |
| | | | |
| Results | | | |
| Electricity Price ($/MWH) | $ 29.13 | $ 32.19 | $ 35.52 |
| Percent vs Aggressive | 100% | 111% | 122% |

| Coal Plant | Aggressive Financing | Historic Financing | Conservative Financing |
|---|---|---|---|
| Assumptions | | | |
| Debt Leverage | 80% | 65% | 50% |
| Debt Tenor | 20 | 15 | 10 |
| Credit Spread | 1.50% | 2.00% | 3.50% |
| Equity IRR Required | 15% | 16% | 17% |
| | | | |
| Results | | | |
| Electricity Price ($/MWH) | $ 29.25 | $ 32.74 | $ 36.68 |
| Percent vs Aggressive | 100% | 112% | 125% |

The analysis illustrates that policies to promote the development of merchant power which lower the cost of capital such as bilateral contracts have important long-term impacts on electricity prices. The graph begins with a base case and measures how much prices move up or down from the base case because of the assumption change. The analysis demonstrates the key role the ADB can play in the industry through providing financing that increases the debt capacity of MPPs. The tornado diagram below demonstrates which aspects of financing are most important to policies that affect the cost of capital. The graphs show that debt leverage and the length of the debt tenor are the most important factors that affect the cost of capital of combined cycle and coal MPPs.




## 5.9 Analysis of Alternative Capacity Pricing Systems, and Price Caps

### 5.9.1 Alternative Capacity Pricing Policy

The above discussion of forward price simulation models involves how price projections apply to individual merchant plant transactions. Through simulating the exercise of market power, capacity additions driven by bilateral contracts, price caps, transmission pricing and alternative capacity pricing structures, the forward price models can be used to measure potential costs of different policy alternatives on customers. In modelling of different policy options, the ADB can fully understand the mechanics and pros and cons of the different alternatives.

Previous parts of the MPP report discussed general issues associated with the design of capacity markets. We separated capacity markets into three general categories – energy only markets, installed capacity markets and markets with capacity up-lifts. Alternative market capacity market structures have been applied throughout the world and there is no consensus as to the most appropriate market structure. For example:

- Energy only markets in California, Australia and Scandinavia apply a bid-based structure where there is no explicit difference between capacity and energy prices. In these markets there is a system of demand bidding that is intended to incorporate demand elasticity in the prices.

- Installed capacity markets are used in the Northeast region of the US including the New England pool, the New York pool and the PJM pool.

- Capacity uplift systems were used in the original UK market and are applied in the Argentinean market.

- Capacity payments from a modelling process are added to energy prices have been applied in Columbia and South Korea. For example, in Columbia capacity payments made by simulating hydro scarcity and the operation of thermal plants under scarcity conditions while capacity payments in the South Korea market are added to stranded investment charges.

In addition to the alternative market designs for capacity prices, countries can include a variety of policies that driven by some kind of administrative process. These features include price caps to address market power and price volatility in all of the markets; reserve margins in installed capacity markets and pre-determined assignments of the value of lost load in capacity up-lift markets. For example the price cap is $1,000/MWH in the New England pool and it is AUD 10,000/MWH in Australia; the reserve margin targets in the US PJM market are about 17% and the VOLL adder in the UK market was about $2,500/MWH. Each of these administrative determinations can affect capacity expansion, profitability of MPPs, system reliability, pricing and other factors.

Appendix 3 describes technical issues associated with capacity prices in forward price simulation models. Subjects include the definition of capacity prices; the optimization process for determining new capacity with different capacity pricing structures; and, incorporation of the value of lost load and loss of load probability in modelling. In constructing long-term pricing models under different market frameworks markets can be separated into those which involve a capacity price that on an hourly basis and those that involve separate installed capacity markets. The former includes bid-based markets where the value of lost load is determined by market forces and capacity uplift markets where the value of lost load is determined by an administrative process. The later structure involves a capacity market which is separate from the energy markets but has a very significant effect on energy markets.

### 5.9.2 Capacity Prices from Hourly Bids

***Policy Basis for Energy-Only Market Design***

The notion of an energy-only structure for market prices is relatively new. Not very long ago, discussions of electricity generation pricing invariably included a distinction between capacity prices applied on the basis of kW and energy prices measured in terms of MWH. Tariffs for large commercial businesses virtually anywhere in the world still generally include both a demand charge to cover capacity costs and an energy charge to compensate electricity providers for the cost of producing energy. The concept of a capacity payment separate from an energy payment originated with the French economist Bolieux. His contribution was the idea that energy price should be set at marginal cost for each period and then the capacity payment should recover the difference between fixed investment costs and the energy price from on-peak users.

Nowadays, when discussing market pricing of generation it is often considered old fashion to distinguish between capacity prices and energy prices. Instead, the “modern” way of evaluating what was formerly called capacity prices is to think in terms of price spikes and call options. The hourly bid-based market provides a number of theoretical benefits. The hourly market gives customers short-term price signals to promote them to use electricity efficiently rather than roughly attributing capacity to on-peak periods. For example, customers can choose to interrupt their use of electricity from market determined supply and demand conditions rather than a set of arbitrary determined criteria incorporated in tariff rates. The energy-only market also provides signals to build, operate and maintain capacity in an optimal manner.

If there is no market power and if financial markets efficiently attract capital to build new capacity, an hourly bid-based market framework leads to the most efficient system from an economic efficiency standpoint. The bid-based hourly market with no market power and no constraints on capital attraction is analogous to perfect

competition used in micro-economic theory. As with perfect competition, the ideal bid-based market may never occur in practice, but the model is worth studying because it is a starting point that provides a basis upon which to evaluate less optimal market structures.

If capacity is priced on an from energy-only markets, sudden price spikes are necessary in order to justify construction of new plants (see the insert describing price spikes in US markets.) Without the presence of relatively extreme though infrequent price spikes, new capacity will not be built and the market cannot reach equilibrium. Because of the price spikes that arise when existing capacity is fully utilized, there is no need for a capacity price measured using a $/kW/Year basis to add to energy markets. To illustrate how price spikes can encourage new capacity consider a case with ten hours of price spikes of $6,000/MWH. For owners of generating plants, the price spikes yields revenue of $60,000 for each MW of capacity. Converting the megawatts to kilowatts through dividing by 1,000 implies a capacity price of about $60/kW/Year which is approximately equivalent to carrying charges on a new peaking plant. If there are twenty hours instead of ten hours of price spikes, price spikes equate to $200/kW/Year – a level that very likely covers the carrying charge and fixed operation and maintenance expense of peaking plants by a wide margin.

While the bid-based energy framework has clear theoretical benefits, there are two problems with this system that occur because the assumptions behind the perfect market do not hold. These two assumptions include (1) the assumption of no market power and (2) the assumption that an energy-only market can attract sufficient capital to build sufficient new capacity.

The problem of market power during periods of capacity constraint in bid based market is a central policy question in the design of markets. Given the magnitude of profits that can be earned by generators when price spikes occur, it is not surprising that suppliers will attempt to push markets into price spikes. Furthermore, since it is likely that most capacity will be dispatched at times when prices spike, there is less natural incentive to bid at marginal cost. When capacity is constrained, even if there are multiple plant owners, market power can be exercised by withholding capacity on an economic or a physical basis. Economic withholding involves making bids at much higher levels than marginal cost while physical withholding involves removing some capacity from the bidding process in order to push the market into a capacity constraint. To see why bid-based hourly markets that rely on price spikes can cause market power problems, consider how incentives during price spike periods contrast with incentives when surplus capacity exists. When a large surplus of capacity exists and where multiple different plant owners make bids, robust competitive pressure exists to make energy bids at marginal cost because of the chance that plants will not be dispatched. (Demand bids can moderate this market power; but demand bids have virtually never been robust.)

A second policy issue with bid-based markets is the question of whether financiers will put their money at risk for plants that earn most of their profits in a few hours of the year. Further, in years where demand is low because of the weather or because of weak economic conditions, there may be no price spikes and no profit. The extreme volatility of the capacity component of prices mean reduce the amount of debt financing for power plants and make it very difficult to raise money for peaking plants. Conversely, the solution to this problem lies with forward contracts with retailers, who must manage the risk of weather driven price spikes, and who generally are unable to pass the price spikes through to their customers.

The potential of suppliers to exercise market power and the volatility of cash flow to suppliers has lead to various suggested interventions in bid-based markets. A prominent market intervention is implementation of price caps. While price caps limit the exercise of market power, the caps also influence consumption decisions, the willingness of retailers to forward contract, and capacity addition decisions made by suppliers. Because price caps interfere with optimal decision making, the price caps increase costs in prices in the market relative to the perfect market ideal. To evaluate tradeoffs between market power problems and optimal decision making, an analytical model can be used.

***Analytical Modelling of Bid-Based Capacity Pricing Systems***

In energy-only markets the reserve margin, the capacity mix and the loss of load probability are outputs of the forward price simulation model rather than inputs. The reserve margin results from an optimization process where new plants construction is driven by value. The model is developed so that alternative price caps, different assumptions regarding the exercise of market power alternative carrying charge assumptions. Modelling of price caps simply involves entering a constraint and limiting prices to the price cap level if the unconstrained market would result in prices higher than the capped amount. Exercise of market power is modelled through assuming that in constrained hours and high price hours, market prices are increased by an assumed fixed percentage.

The table shown at the beginning of Section 5.8 presents relative customer costs in four scenarios with respect to bid-based markets. The first scenario is the "perfect market" with no market power. This scenario is assigned an index value of 1.0 for comparative purposes. The second scenario assumes uses the energy-only structure, but assumes exercise of market power during periods when there are high levels of demand – prices are increased to 30% above their cost whenever the level of reserves is below 20%. The third and fourth scenarios apply price caps to limit the market power. In the first price scenario a price cap of $1,000/MWH is assumed and in the second scenario, a price cap of $300/MWH is assumed. These two scenarios increase costs to consumers because the amount of capacity less capacity is added to the system and the mix of capacity is not optimum.

***Policy Basis for Capacity Up-Lift Market Design***

The bid-based markets described above are generally structured with pools or short-term bilateral contracts where the energy bid is not necessarily equal to the variable cost of a plant. In some markets, such as Argentina, South Korea and Columbia, a cost based system rather than a bid-based system is used to market energy prices where suppliers cannot bid at prices that differ from variable cost. The cost based model limits market power that arises from economic withholding, but it results in problems that were described above with the short-term price model where the market is not sustainable. A system of capacity up-lifts can also incorporate the probabilistic nature of capacity prices. In the energy-only market, capacity prices result from actual times at which capacity is fully utilized. The fact that near full capacity should prompt a capacity price to assure reliability is not reflected. To resolve the structural problems in a cost based system, a capacity uplift is added to the cost-based energy price. The initial UK system (which was not cost based) added a capacity price to the short-term marginal price (SMP) using the formula:

Capacity Price/MWH = (Administered VOLL – SMP) x LOLP

The capacity price uplift model addresses some of the problems with the energy-only model. Establishment of an administratively determined VOLL eliminates the need for price caps and addresses the problems with demand side bidding that have occurred in most markets. Since the pricing of VOLL is fixed while the price during constrained periods is variable in the unconstrained energy-only market, there is less capacity price volatility in the up-lift model. (Both models have price volatility arising from uncertainty associated with the times at which capacity constraints occur.) The problem with capacity uplift models is that the VOLL is set by an administrative process which does not match the real cost that consumers face during capacity constraints. This administrative process is subject to extreme pressures from suppliers on the one hand and consumers on the other hand.

***Policy Analysis for Installed Capacity Market***

Installed capacity markets have been implemented in various markets as an alternative to the bid-based systems and the capacity uplift systems discussed above. These installed capacity market systems consist of two different markets – one for capacity and one for energy. The idea is that bidding for capacity and cash flow received from capacity prices will result in an overall market price that allows MPP developers to build new capacity. Market prices for capacity are measured on the basis of installed capacity – e.g. kW – rather an energy basis. As explained below, installed capacity markets can be managed to assure a reliable level of capacity and moderate levels of price volatility. Further, since installed capacity markets reduce price spikes and since market power is most problematic during price spikes, installed capacity markets can mitigate the exercise of market power.

Installed capacity markets come about because of reserve margins that are dictated by the edicts of a market regulator. Installed capacity has no real economic meaning as explained in Appendix 4, but a market is created by the regulatory requirement that distributors and retailers must contract for capacity. Creation of a market derived from the edict of a market regulator is analogous to other markets where the government establishes a market for a product that would have no utility but for the government regulation. Markets for emission credits where power plants must have permits to emit pollutants are an example of a government regulation creating a market that would otherwise not occur. Safety regulations can create similar markets in products such as seatbelts. In the case of installed capacity, the regulation defining the reserve margin establishes the market. If consumers are forced to demonstrate that they have actual installed capacity, they will bid for the lowest cost capacity from suppliers who own the physical capacity. Suppliers will compete to sell capacity driven by the opportunity cost that consumers incur through buying the lowest possible capacity on their own behalf. In equilibrium, capacity prices should approximate the carrying cost of peaking capacity less the amount peaking capacity would earn from energy sales.

Given the discussion of bid-based systems, a natural question arises as to why a separate market for installed capacity is necessary. The PJM, New York and New England markets all have bid-based energy markets where prices can spike to high levels. As explained in Appendix 4, the price spikes compensate developers for carrying charges on the construction of new capacity. The reason both capacity markets and bid-based energy markets can co-exist and result in reasonable prices involves the relationship between capacity and energy markets. The higher the level

of capacity in a market, the lower will be the level of energy prices. If regulations that define a capacity market force a high level of surplus capacity, the high revenues earned in installed capacity markets should be off-set by lower revenues from selling energy at spot prices.

To illustrate pricing in a capacity market, assume that a reserve margin of 20% is required by the regulator. Also assume that without a capacity market, the equilibrium reserve margin would be 11%. The 20% reserve margin would imply that each supplier receives capacity payments that could not be justified in the bid-based system. However, the energy prices will be lower because there will be fewer price spikes and because the supply curve is shifted to the right. The policy question is whether the costs customers incur in making capacity payments offset the benefits of reliable capacity and lower price volatility.

The volatility of electricity prices from installed capacity markets is difficult to evaluate. While volatility of prices on the hourly markets is reduced, the volatility of capacity markets can be extreme. When surplus capacity above the reserve margin requirement exists, the opportunity cost of capacity is very low – the amount it takes to keep capacity from being retired. On the other hand, when the reserve margin is far enough below that reserve margin requirement that new capacity cannot be built because of construction lead times, the capacity price can become very high.

### 5.9.3 Policy Issues Associated with Bilateral Contracts

Bilateral contracts are important in establishing markets and have been discussed a number of times in previous sections. In this section we discuss how some of the costs and benefits associated with bilateral markets can be quantified. Benefits of bilateral markets include lower costs of capital and lower prices for consumers; lower price volatility and less potential for the exercise of market power. These benefits are offset by various problems. First, without regulatory intervention consumers or consumer representatives will be reluctant to sign long enough contracts to enable financing in practice. Second, if all power in the market is under contract, the benefits in terms of providing price signals to customers will be blunted. With most power under contract, fewer consumers see prices and the advantages of demand response in terms of economic efficiency are reduced. Similarly, fewer suppliers make decisions from price behaviour of the energy-only volatile market prices. If virtually all of the capacity is locked into long-term contracts then prices in those contracts rather than all of the supply and demand factors drive both consumers and producers in the market.

> California law required the electric utilities to divest their electric generation assets, prohibited their electric utilities from entering into forward long-term, fixed price electricity contracts or similar hedging arrangements, and required the electric utilities to purchase 85% of their electric needs from the daily spot market, commonly called “The Power Exchange.”

Even if bilateral contracts comprise the whole market, spot prices will still be computed from a making stacking the bids and the cost of each generating unit. These spot prices can be used to establish the contract prices. Further, contracts can be structured so that customers have an incentive to reduce usage when prices increase above contract levels.

## 5.10 ADB Procedures for Participating in MPPs

The final section of the first component considers potential ADB products including insurance, mezzanine finance and long-term debt financing of MPPs to provide a catalyst to their development.

The roadmap leading to the market structure defined in Section 5.2 should lead to transparent pricing, economic efficiency, equitable pricing structures and risk allocation where suppliers of capital incur the costs and benefits of good decisions and mistakes. Various potential innovative products created by the ADB could promote development of this framework. Some of these potential products include:

### 5.10.1 Financing of Hybrid Plants that Cover Merchant Periods

The ADB can provide financing for longer tenors than many commercial banks or other financial institutions. For example, if a plant has a bilateral contract for six years, the ADB may provide debt financing that matures after the merchant period over years seven through fifteen. The notion of "filling the gap" has been recognized by the ADB in other situations. This notion will be particularly important in the financing of MPPs.

### 5.10.2 Insurance for Problems with Off-takers

As stated often in the report, contracts are only as strong as the credit quality or the off-taker. The risk of companies being able to support contracts is increased in competitive markets because of the potential that contracts will be out of the market. Because of perceived risks associated with retailers and distributors in a market transition that are often not guaranteed by the government, an ADB insurance product could be developed to guarantee contract payments. This is very similar to the breach of contract insurance that is currently provided by the ADB.

### 5.10.3 Mezzanine Finance

Given the problems in financing merchant power plants due to perceived risk associated with the volatility of power prices, an ADB product that provides subordinated debt may be very helpful in promoting development of plants in Asia. The modelling analysis above demonstrated how mezzanine finance can be priced in the context of merchant power including how to price the debt and how the addition of subordinated debt affects the credit quality and pricing of senior debt. As with provision of longer debt tenors to lower the cost of capital for MPPs, the ADB could fill a gap through providing subordinated financing.

### 5.10.4 Stranded Investment Debt Facilities

Charges for stranded investment are low risk government cash flows with government backing. These cash flows should support a high level of leverage which can be used to reduce the cost of transition. Stranded investment bonds have been

developed in the US where the bonds generally have a AAA bond rating. The ADB could develop similar instruments for developing countries in Asia.

### 5.10.5 Insurance for Currency Price Fluctuations of Developing Countries

Unlike plants that have long-term PPA contracts, merchant plants generally will not have currency protection where contract prices in local currency fluctuate in order to meet financial obligations in US dollars. Rather, the merchant plants derive revenues from electricity spot and contract markets that are expressed in local currency. The added risks of currency fluctuations cannot generally be hedged on a long-term basis in futures markets. Therefore, an ADB product that provides currency devaluation protection can be important to the development of new plants.

### 5.10.6 Traditional Risk Insurance Products and Loans

Merchant plants in developing countries will involve the same political risks involving currency conversion, nationalisation and terrorism as other projects. As such, the traditional ADB insurance products will be important in developing the industry. In addition, the traditional ADB loans can be important for financing MPPs. The loans should be modified in order to include cash flow sweeps and dividend restrictions as well as flexible re-payment structures where pre-payment of debt is not precluded.

# APPENDIX 1: COMPUTATION OF VOLATILITY

The volatility of a time series can be estimated by computing the standard deviation of the percent change in price from one period to the next and adjusting the result for the length of the time period in historical data and the pricing model. Adjustments for the length of the time period are necessary because volatility is generally expressed in annual terms. The process for calculating volatility involves first computing the standard deviation of the rate of return from one period to the next. Once the periodic standard deviation is computed, an adjustment is made so that the parameter is computed on an annual basis. The following formulas review volatility formulas using discrete and continual compounding. First, the rate of return over the period for reporting prices is computed:

Discrete Compounding:

$$\textit{Rate of Return}_i = \text{Price}_i/\text{Price}_{i-1} - 1$$

Continual Compounding:

$$\textit{Rate of Return}_i = \text{Ln}\,(\text{Price}_i/\text{Price}_{i-1})$$

Next, standard deviation of the periodic rate of return is computed. If the prices are reported on an annual basis, this is the volatility.

$$\textit{Period Volatility} = \text{Standard Deviation}\,(\textit{Rate of Return}_i)$$

The final part of the process for periodic prices that are not computed on an annual basis is converting the period volatility to an annual figure. Because of the mathematical process that defines Brownian motion, standard deviation of the rate of return increases with longer time periods. The variance of Brownian motion increases directly with time and the standard deviation increases with the square root of time. This means the period volatility defined above is multiplied by the square root of time measured in years (□) to develop the annual volatility. Annual volatility is therefore defined as:

$$\textit{Annual Volatility} = \text{Standard Deviation}\,(\textit{Rate of Return}_i) \times (t)^{1/2}$$

For a random walk (Brownian motion) time series, the length of the time period used to measure volatility does not significantly impact the estimated volatility parameter. For example, in the stock price example presented in the workbook, the volatility is 17.3% if the first half of the sample is used and 17.0% if the second half of the sample is used.

# APPENDIX 2: MONTE CARLO SIMULATION PROCESS

To apply Monte Carlo simulation to time series models, the following five step process is used:

Step 1: Establish the number of time periods (the period could be a day, a month or a year) and the number of simulated price paths.

Step 2: Begin with the first price path and draw a random number between zero and one.

Step 3: Convert the random number into a factor to apply to the price series through filtering the number through a probability distribution such as the normal distribution. For example, if the filter is the normal distribution, numbers between 0 and 1 are converted to numbers between -4 and 4.

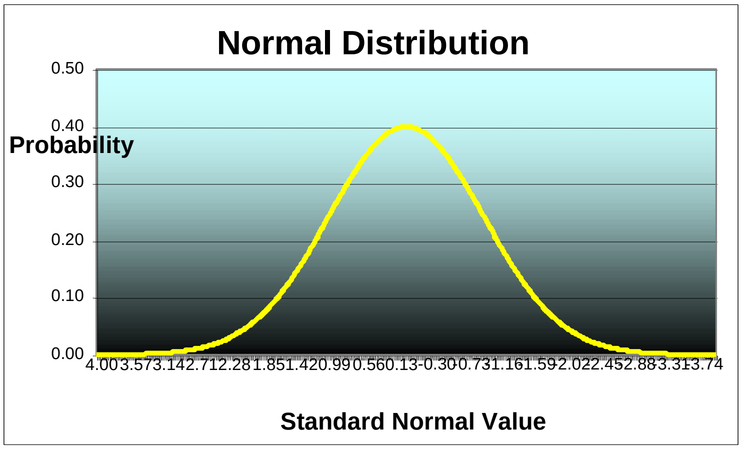
Step 4: Multiply the filtered random number by the volatility parameter which magnifies the effect of volatility on the potential price movement.

Step 5: Repeat the process of drawing a random number, filtering it through a probability distribution and magnifying it with the volatility parameter for each period.

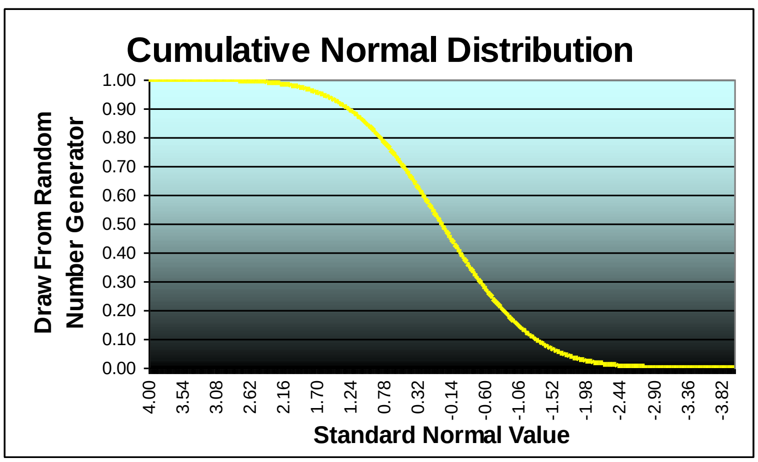
Step 6: Once the process is completed for one price path, begin the same process for the next simulation and continue to repeat the procedure for the total number of simulations.

To illustrate this process assume an analysis is developed for 20 months with a volatility of 20% and a starting price of 15. A random draw will be made for the first month. Say the random number is .6. A value of .6 translates into a standard normal value of .25. This number is multiplied by the volatility of 20% yielding a percent change in price of .25 x .2 or 5%. The price in the next period therefore is 15 x 1.05 or 15.76. In the next period, the same process is used, but the price is 15.76 instead of 15. Then the price will move and another draw will be made resulting in a new price. By the 20th period, this single price series will reflect the impacts of pulling from the random generator 20 times. Once the process for the first path is established, the same process is used to generate another time series. Ultimately, the process can be redone many times for the 20 year period – often making 1,000 to 100,000 price simulations.

In converting the random draw to a periodic price movement, Monte Carlo simulation can be used with any type of probability distribution deemed appropriate to represent the nature of a price moves. Filtering random draws through a normal distribution implies that it is more likely for the variables to fall near the prior period price than far away from the prior period price. The graph below illustrates a normal distribution with a mean value of zero and a standard deviation of 1.0 which is known as a standard normal distribution.




The random number generator that pulls numbers with an equal probability between zero and one can be transformed to a normal distribution resulting in standard normal values between -4 and +4. For each standard normal value, the probability is accumulated beginning with the standard normal value that has a probability of zero. The process of applying Monte Carlo to price movements using a cumulative normal distribution can be visualized by thinking about the random number occurring on the vertical axis being converted into a number on the horizontal axis. On the cumulative normal graph, it is more likely that the standard normal number will occur when the line is steep than when it is flat.




Using a standard normal distribution, the movement of a price series is simulated through multiplying the volatility by the standard normal distribution – a number with a range of about –4.0 to +4.0 with 99.9% probability. The impacts of the simulation depend on the volatility. If the volatility is zero, it does not matter whether the standard normal distribution is zero, one, negative one, or four. If the volatility is a high number, the impacts of "pulling" from relatively low probability occurrences on the simulated price is bigger. The random number can vary between zero and one. For example, if the random number is .5, the standard normal value is zero. If the random number is .6, the standard normal value is -.14. The random number must be above .9 or below .1 for the standard normal value to be greater in absolute value than 1.0.

# APPENDIX 3: LONG-RUN MARGINAL COST FRAMEWORK FOR EVALUATING MERCHANT POWER PLANT INVESTMENTS

**Current Energy and Capacity Cost Levels**

The traditional way marginal costs, prices and many other issues have been evaluated in the utility industry is to separate the analysis between capacity costs and energy costs. Energy cost is defined as the lowest cost of energy at generating units not currently producing energy for other uses. Capacity cost can be defined as the lowest cost of available capacity to provide "insurance" that energy will be available drives pricing of capacity. For example, electricity prices to industrial customers around the world are almost universally separated between demand charges for capacity and energy prices for energy usage. This conventional method of separating capacity and energy costs and prices is often still applied in pricing and valuation analysis, but it is also possible to evaluate market prices that combine energy and capacity prices in one number through "financially firm" market prices.

Current energy prices are driven by marginal energy costs which in turn are the variable cost of the most expensive increment of capacity that is generating energy in any time period. If all of the available generating units on a system are operating and/or the load of interruptible customers is cut, marginal energy costs are defined as the most expensive cost of the generating unit that is operating in an hour. During low load periods, market prices are bid to the marginal cost levels. During capacity constrained periods the marginal cost of energy is not the cost customers would be willing to pay to be in the group of customers that is not curtailed as explained in the interruptible analysis above.

Capacity prices can be defined as the amount paid for firm electricity over and above the price of interruptible energy. In a competitive market, the capacity price can be thought of as the cost of "firming-up" interruptible energy prices and guaranteeing that energy will be delivered. While the nature of capacity prices may change in a competitive market (i.e. capacity prices may not be expressed in terms of dollars per KW-year), some level of capacity price must exist to keep existing plants operating and to promote the construction of new plants.

**Cost Structure of Alternative Technologies**

The cost which prices must cover depends on the type of plant that would be constructed and whether multiple technologies or a single technology would be added. To introduce the notion of long-run marginal cost, assume that a single technology has lower fuel prices and lower capital costs than other technologies. In many markets a natural gas combined cycle plant ("NGCC") is used as a single technology to represent long-run marginal cost. For example, Singapore, Australia and New Zealand have used the cost of an NGCC to represent long-run marginal cost and form the basis for bilateral contracts. Long-run marginal cost benchmarked to costs of building and operating an NGCC plant involves adding fuel costs and other operation and maintenance costs to the carrying charges required to finance the investment.

The table below illustrates the cost of a natural gas combined cycle plant from the MPP database using various assumptions and a capacity factor that reflects operation during all hours that it is available. The cost analysis is driven by the merchant carrying charge structure described in the section above, which results in a carrying charge rate of 11.4%. As the accompanying table shows, the price that is required to yield a 14% return is $35.43/MWH. This price is above the

actual market prices described above. The analysis therefore suggests that prices are below equilibrium prices for base load power.

| 22 | Natural Gas Combined Cycle Pl | 1 | Natural Gas Price/MMBTU |
|---|---|---|---|

**Basic Assumptions Used in Project**

| | Data In Annual Sheet (1-Yes) | Constant Inputs When Flag = 0 | |
|---|---|---|---|
| Capacity of Project | | 530 | MW |
| Capital Cost/Unit of Proje | | 616 | $/kW |
| Capacity Factor | 0 | 90.25% | |
| Variable O&M per Hour | 0 | $ 1.75 | $/MWH |
| Fixed O&M per Year | 0 | $ 18.20 | $/kW/Year |
| Other Costs (Insturance etc.) | | $ - | $ |
| Heat Rate | 0 | 7,056 | BTU/kWh |
| Fuel Cost | 0 | $ 2.750 | $/MMBTU |
| Input Cost Escalation | 0 | 3.0% | |
| Life of Project | | 25 | Yrs |
| Inflation on Prices | 0 | 2.00% | |
| Inflation Operating Costs | 0 | 2.00% | |
| Tax Rate | | 40.00% | |
| Accelerated Depreciation | | Yes | |
| Tax Life | | 15 | Yrs |
| Emissions Credit Value | | $ - | $/MWH |
| Property Tax Rate | | 1.00% | |

Revenue Input

Debt Sizing From Average Ratios

IRR on Equity

IRR on Project

To fix revenues after establishing IRR, run the IRR and then run Revenue Input Button.

| | |
|---|---|
| Derive Capacity Charges | Yes |
| Apply Prices in PPA Price Sheet | No |

| | | | |
|---|---|---|---|
| First Year Price | $ | 35.43 | /$/MWH |
| Average Price | $ | 45.40 | /$/MWH |
| Levelized Price | $ | 39.71 | /$/MWH |
| Capacity Price | $ | 112.90 | $/kW/Year |
| Carrying Charge Rate | | 18.32% | |
| Energy Price | $ | 21.15 | $/MWH |
| Project IRR | | 9.65% | |
| Equity IRR | | 14.00% | |
| Debt Leverage | | 65.00% | |
| ........... | | 148,475.96 | Reset |

## Equilibrium Market Model and Marginal Cost

Use of a single plant to represent marginal cost will overstate long-run marginal costs if multiple technologies can be efficiently used to meet the requirements of a system with diverse loads. In equilibrium, long-run marginal cost and market clearing prices will be driven by the cost of constructing alternative types of new capacity rather than the single NGCC technology discussed above. The equilibrium marginal cost converges to levels such that the net profit earned by investors who build different types of capacity is the same. Further, the net profit earned by investors in each type of technology should just cover costs of the new technology, including the opportunity cost of capital.

Computation of long-run marginal cost in a market with multiple technologies begins with traditional screening curves and load duration curve analysis. Screening curves compute the total price required to earn the required return by various technologies at different capacity factors. The total price of each technology declines with higher capacity factor because fixed costs – fixed operation and maintenance as well as return on capital – are spread over higher MWH volumes. Once fixed charges are established from summing fixed operation and maintenance costs plus carrying charges, the following formula can be used to compute required prices.

Required Price/MWH =

(Variable Cost/MWH x MWH + Fixed Charges/MW/8,760)/MWH

At low capacity factors, the fixed charges have more effect on the total required price while at high capacity factors, the variable cost matters more. A screening analysis for three plants is shown on the graph below. The peaking plant has a lower all-in cost at low capacity factors and the base load plant has a lower cost at higher capacity factors.

| | | Plant Inputs to Equilibrium Model | | | | |
|---|---|---|---|---|---|---|
| | | Peaker | | Combined Cycle | | Coal |
| Capital Cost - Per KW | | $450 | | $660 | | $1,250 |
| Fixed Charge Rate - Per Year | | 9.50% | | 9.50% | | 9.50% |
| Annual Capital Cost ($/kW) | | $42.75 | | $62.70 | | $118.75 |
| Fixed Non-Fuel O&M Costs ($/kW/Year) | | $5.00 | | $15.00 | | $30.00 |
| Total Fixed Cost ($/kW/Year) | | $47.75 | | $77.70 | | $148.75 |
| Heat Rate (BTU/kWh) | | 11,000 | | 7,000 | | 10,000 |
| Cost per MMBTU | | $ 3.00 | | $ 3.00 | | $ 1.10 |
| Fuel Cost/MWH | | $ 33.00 | | $ 21.00 | | $ 11.00 |
| Fixed Cost: $/KW/Month | | $ 3.98 | | $ 6.48 | | $ 12.40 |

The second step of traditional analysis is integration of a load duration curve that defines energy production from various types of capacity. Load duration curve analysis involves sorting loads over a year from the highest level to the lowest level and placing various different types of capacity underneath the curve. Load duration analysis can be extended to incorporate the unscheduled maintenance outage of plants through computation of an equivalent load duration curve, but for now, a simple representation is used. The load duration analysis “fits” different types of technology underneath the curve until total energy requirements are met. The total energy production divided by the number of hours and the capacity of the plant defines the capacity factor of the plants.

The question to be addressed in capacity expansion analysis and in computing long-run marginal cost is determining what mix of capacity should be used in filling the load duration curve. Three outcomes should occur from computing the optimal mix. First, the capacity factor of the plants should match the capacity factors in the screening analysis. Second, the total cost including variable and fixed cost should be lower with the capacity mix than with any other mix of capacity. Third, the net value of each technology should be the same. Computation of the optimal mix can be made with the “solver” routine in spreadsheet programs once total cost is defined. Mechanics of computing the solver to determine the best mix of capacity is discussed in Section 1 of the workbook using the general approach below:

| | |
|---|---|
| Set: | Capacity factor of each technology to level determined in screening curve |
| By Changing: | Weight of each capacity type |
| Subject to: | Weights greater than zero; weights sum to one |

The use of load duration analysis has been around for a long time and it is very easy to accomplish with spreadsheet tools. This method can also be used to compute long-run marginal cost by adding two simple concepts to the analysis. The first concept is that the energy price in each hour is determined by the cost of operating the highest cost plant on the margin. The second concept is payment of a capacity price driven by the fixed cost of a peaking plant. Using the two simple concepts, a peaking plant does not earn anything from selling energy because the highest level energy prices can reach is the cost of running the plant. Energy and capacity prices are determined by the following two basic formulas:

Capacity Price = Carrying Cost plus Fixed O&M of Peaking Capacity

Energy Price $_{\text{Hour}}$ = Variable Cost of Most Expensive Unit Operating $_{\text{Hour}}$

In this model the net profit earned by a peaking plant is zero because the most it can earn by selling energy is zero and because the capacity cost equals the fixed cost (including the opportunity cost of capital.) Once the peaking plant perspective is established, a similar notion implies that the net profit should be zero for other plant types. For plants other than peaking plants, profit includes the amount earned from selling electricity at a price above variable cost aggregated on an hourly basis, less the fixed costs of the plant. If one type of capacity were more valuable than another type of capacity, the market would not be in equilibrium. This means that the value of new peaking capacity equals the value of building new combined cycle capacity which equals the value of building new base load capacity. For example, if the fixed cost of peaking capacity was $40/kW/Year, implying that all plants realize a capacity price of $40/kW/Year and if the fixed cost of NGCC is $113/kW/Year, the value realized from energy sales at market prices above variable costs of the NGCC plant must aggregate to $73/kW/Year ($113/kW/Year minus $40/kW/Year.) The notion that each technology should have the same value is shown by the following formulas:

| Net Profit = Capacity Value + Energy Price – Fixed Costs – Variable Cost |
|---|

and,

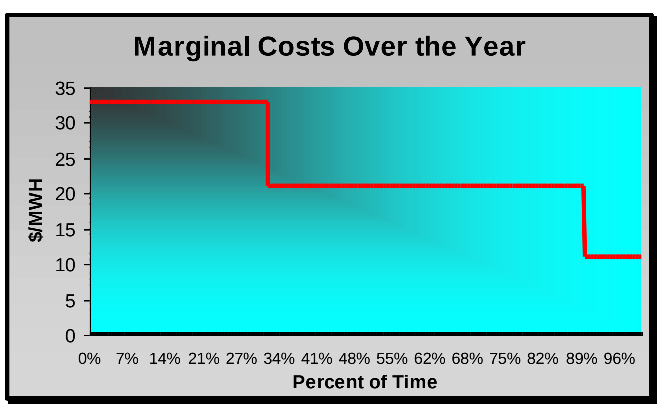
| Value of Energy = $\sum_{Hours}$ Max(Market Price of Energy $_{Hour}$ - Variable Cost of Energy $_{Hour}$) |
|---|

| Value of Capacity = Capacity Price – Fixed Cost |
|---|

in equilibrium,

| Value of Peaking Capacity = Value of Combined Cycle Energy + Value of Combined Cycle = 0 |
|---|

The accompanying graph shows for how much of the year the three plants are on the margin. There are only three price levels on the graph because there are only three plants.




These equations mean that once the capacity mix is optimized, cost-based price of energy at different time periods and the cost-based price of capacity is also defined. The cost-based prices establish the value of different technologies. Therefore, long-run marginal cost in equilibrium can be computed from the load duration analysis and the analysis can be verified by assuring the net value of each new technology is zero. The example below includes a simple model with a peaking

plant, a combined cycle plant and a coal plant. The model computes market prices using a load duration curve relative to the minimum of available energy costs of technology in the market. The capacity mix is varied until the net value of different types of capacity is the same.

The tables and graph below present summary inputs and outputs of the long-run marginal cost model. This model can be used to test the effect how changes in variables affect long-run price outlooks. For example, if the capital recovery rate increases or the price of natural gas declines, the mix of coal declines. If the heat rate on combined cycle plants improve or if the capital cost of the coal plant increases, the mix of gas plants increase. These changes in the capacity mix affect the amount of time plants are on the margin and the marginal cost of energy.

## Summary of Outputs of Equilibrium Model

| | | | | | | |
|---|---|---|---|---|---|---|
| **Average On-Peak Interruptible Energy Cost** | **$ 28.78** | **per MWH** | **All-in Price at Capacity Factor of** | **100.0%** | **$ 29.29** | **per MWH** |
| **Average Off-Peak Interruptible Energy Cost** | **$ 18.93** | **per MWH** | **All-in Price at Capacity Factor of** | **75.00%** | **$ 32.11** | **per MWH** |
| **Average All Hours Interruptible Energy Cost** | **$ 23.84** | **per MWH** | **All-in Price at Capacity Factor of** | **50.00%** | **$ 36.40** | **per MWH** |
| **Capacity Price** | **$ 47.75** | **per kW/Year** | **All-in Price at Capacity Factor of** | **25.00%** | **$ 50.58** | **per MWH** |

| | Capacity Percent | Energy Val per kW | Capacity Cost/kW | Net Capacity Value/kW | Capacity Value Deviation | Capacity Factor |
|---|---|---|---|---|---|---|
| Peakers | 25.00% | $ - | $ 47.75 | $ 47.75 | $ 0.08 | 8.81% |
| Combined Cycle | 25.00% | $ 30.59 | $ 77.70 | $ 47.11 | $ 0.12 | 57.33% |
| Coal | 50.00% | $ 101.22 | $ 148.75 | $ 47.53 | $ 0.00 | 89.39% |
| Average | | | | $ 47.47 | $ 0.21 | |

| | Capacity MW | Energy Generation | Energy Value | Fuel Cost per MWH | Generation Percent | Capacity Cost | Net Value |
|---|---|---|---|---|---|---|---|
| Peakers | 5,637 | 4,348,207 | $ - | $ 33.00 | 3.85% | | |
| Comb Cycle | 5,637 | 28,310,215 | $ 172,418 | $ 21.00 | 25.07% | 168,835 | 3,583 |
| Coal | 10,250 | 80,258,696 | $1,037,430 | $ 11.00 | 71.08% | $ 1,035,200 | 2,230 |

# APPENDIX 4: THE THEORY OF CAPACITY PRICING

**Introduction: The need for capacity prices**

A cost based pricing model described in Appendix 5 does not meet the fundamental principle of allowing investors in new generating plant to earn a reasonable profit level. The fact that the model is not sustainable can be demonstrated by considering how investors in new peaking capacity earn profits on their investment. Where electricity prices are limited to the marginal operating cost of generating units, the highest level prices can reach in any hour is the operating cost of the capacity with the most expensive variable operating cost or peaking capacity. In hours when the peaking plant does not operate, the plant does not earn a profit. Similarly, in hours when the plant operates, the price is equal to the operating cost and the plant also does not earn a profit. This means that owners of a peaking plant do not earn sufficient revenues to make contributions to the fixed costs of maintaining the plant or the fixed capital costs of their plant.

In the model where prices are limited to the operating cost of the most expensive dispatch with no ability to recover costs of capital, investors would not construct new peaking capacity. This may not seem like a crucial problem, but the lack of new capacity would lead to cascade of other problems. First, existing peaking would face a similar problem as new capacity in that it could not recover fixed costs of operating the plant and therefore all of the existing capacity would be retired. With no peaking capacity, the most expensive unit to run on the system becomes the next most expensive plants to operate such as intermediate combined cycle capacity. As these would now be the plants with the highest variable cost, no new intermediate capacity would be build and existing intermediate capacity would be retired as was the case for peaking capacity. Next, the most expensive capacity would have lower cost and so on ultimately resulting in the retirement of all capacity. This discussion of problems with a market limited to marginal energy cost demonstrated that models of long-term prices must ultimately be above marginal energy costs.

A central question in analysis of long-term pricing is determining the amount by which equilibrium prices exceed marginal energy costs. In simple terms, the amount by which prices exceed the energy pricing can be labelled capacity prices. (This definition assumes no exercise of market power, which can also cause prices to exceed marginal cost.) Much of the remainder of this discussion addresses how to project the level and the amount of capacity prices. Capacity prices are related to long-run marginal cost and energy prices through the following equations:

| |
|---|
| Long-run Marginal Cost of Generation/MWH =<br>Variable Operating Costs/MWH +<br>(Carrying Cost/MW)/Hours Dispatched |

and,

| |
|---|
| Equilibrium Price/MWH = Long Run Marginal Cost of Generation/MWH |

where,

| |
|---|
| Equilibrium Price/MWH = Capacity Price + Energy Price/MWH |

and, because no market power is assumed,

| |
|---|
| Energy price/MWH = Marginal Energy Cost/MWH |

Note that the carrying charge is a crucial component in evaluating long-run marginal cost. Carrying charge rates were addressed in detail in Appendix 1.

**Capacity Additions and Capacity Prices in Competitive Markets**

One of the basic reasons to deregulate generation markets is that when prices are set by competitive forces of supply and demand, in theory, economically efficient decisions will be made with respect to construction, operation and retirement of generating plants. In contrast to deregulated markets, non-market frameworks include state-ownership, long-term PPA contracts with independent generators, and rate of return regulation. All of these non-market approaches have been criticized because of low productivity, corruption, surplus capacity, inefficient capacity mix, little innovation and excess profits to generation companies. A central question with respect to evaluation of different market capacity price structures is therefore whether a market system can improve on the non-market systems from the standpoint of efficient plant operation, construction of an optimal amount of capacity and construction an optimal mix of capacity.

In developing long-range price forecasts, analytical models are constructed for three capacity pricing frameworks. The three capacity pricing systems include energy-only markets, installed capacity markets, and markets with administratively determined capacity prices applied to loss of load probability measurement (labelled below as capacity price up-lifts). In the first type, energy-only markets, capacity prices are not distinguished from energy prices. Recovery of capacity prices comes from price spikes during hours when capacity is scarce. The second framework, installed capacity markets, is driven by an administratively determined level of reserve margin. Capacity prices in these markets are expressed as a monetary amount related to the level of capacity regardless of the actual usage (e.g. $/kW/Year). The third system, capacity price up-lifts, involves computation of loss of load probability for each hour and application of an administrative price to the probability statistic. The administrative price, also known as value of lost load (VOLL), is expressed as a monetary amount per MWH.

**Optimal Aggregate Capacity Level**

To develop models of capacity prices and to evaluate whether the models result in optimal capacity levels and an optimal capacity mix, the relationship between capacity pricing and construction of new capacity must be established. Capacity pricing models are derived in part from the way in which new capacity is assumed to be built. Analysis of capacity price levels that result from application of the alternative capacity market designs must begin by addressing how private investors decide to construct new plant and how generating companies decide whether to retire existing capacity.

A plant earns profit to recover fixed operation and maintenance expenses as well as carrying costs by receiving revenue from market prices above its variable operating cost. To explain how investors earn profits and build capacity in different capacity market structures, consider a simple representation market with only peaking plants. A peaking plant earns its profit margin from periods (hours) when there is a need to allocate scarce capacity and price spikes occur in energy only markets; from market clearing capacity prices in the installed capacity markets; and from the loss of load probability multiplied by the value of lost load in the capacity uplift model. The margin for a peaking plant in alternative market frameworks can be illustrated by the following formulas:

*Energy Only Market:* Price Spike/MWH x Generation (MWH) of Peaking Plant

*Installed Capacity Market:* Capacity Price/MW/Year x Peaking Capacity (MW)

*Capacity Price Up-Lift:* VOLL/Hour x LOLP (in Each Hour) x Hours

If the expected profit margin from the above formulas is above the carrying cost plus the fixed operation and maintenance of generating plants, new capacity will be constructed. In other words, new capacity is constructed according to the formulas in the various market structures:

Construct new generating plants when:

| |
|---|
| Expected Operating Margin > Capital Recovery + Fixed Operating Cost |

or, in the case of energy only markets, when:

$$\sum_{\text{Operating Hours}}(\text{Electricity price/MWH} - \text{Variable cost/MWH}) > (\text{Fixed Operating Expense} + \text{Annualized Capital Cost})/\text{MW/Year}$$

or, in the case of installed capacity markets, when:

$$\sum_{\text{Operating Hours}}(\text{Electricity price/MWH} - \text{Variable cost/MWH}) + \text{Capacity Price/MW/Year} > (\text{Fixed Operating Expense} + \text{Annualized Capital Cost})/\text{MW/Year}$$

or, in the case of capacity price up-lift markets, when:

$$\sum_{\text{Operating Hours}}(\text{Energy price/MWH} - \text{Variable cost/MWH} + \text{LOLP}_{\text{Hour}} \times \text{VOLL}) > (\text{Fixed Operating Expense} + \text{Annualized Capital Cost})/\text{MW/Year}$$

Once new capacity is constructed, the capacity price will be affected. Ultimately, in equilibrium, the amount of capacity that is constructed is the amount that yields equality in the above formulas. In the long-run pricing models described below, there are optimization routines that add capacity in amounts such that the capacity price from the various formulas yields a result where the electricity prices result in new capacity earning its cost of capital.

**Optimal Capacity Mix**

Models of capacity prices depend on the mix of capacity as well as the level of capacity. The way in which models optimize the mix of capacity as well as the amount of capacity can be illustrated by assuming a simple situation with only two types of plants – peaking plants and base load plants. Optimization of the capacity mix in long-term pricing models is driven by the simple notion that if it is more profitable to construct one type of capacity rather than another, the more of that type of capacity will be built. In terms of simple formulas with two types of capacity in markets where aggregate new capacity is necessary:

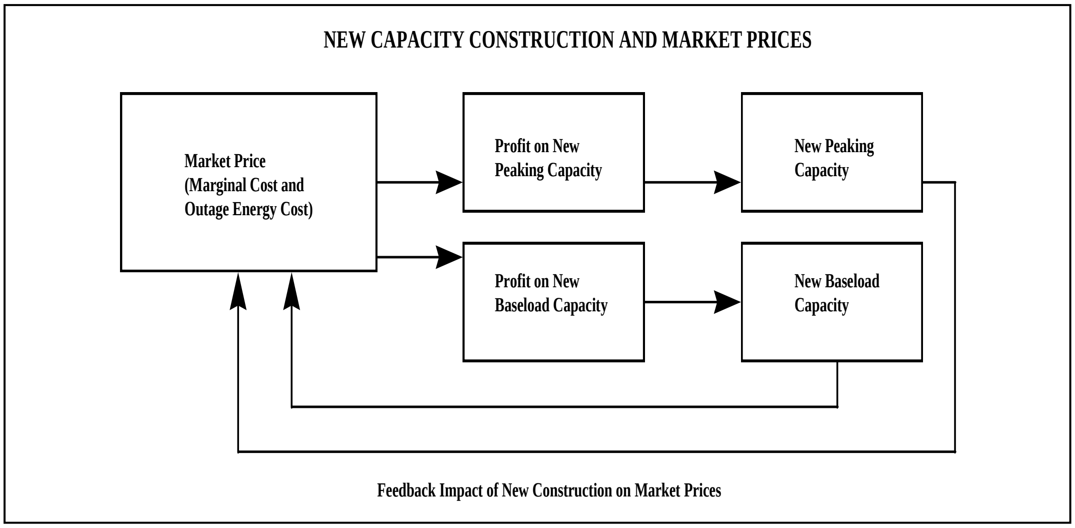
| |
|---|
| If Peaking Profit > Baseload Profit, then Construct Peaking Capacity |

and,

| |
|---|
| If Peaking Profit < Baseload Profit, then Construct Baseload Capacity |

In equilibrium, the profit on peaking capacity must equal the profit on base load capacity. For example, if there is too much base load capacity relative to peaking capacity, the profit potential will be lower for base load capacity than for peaking capacity and more peaking capacity will be

constructed. Eventually, the amounts of alternative new types of capacity will adjust so that the profitability of alternative types of capacity becomes equivalent. The capacity pricing model should therefore have optimization routines that adjust the amount of different types of capacity until the net profit is the same for different types of plants. The relationship between market prices and capacity is illustrated in the diagram below.




The optimization process for adding new capacity in situations where there is deficit capacity can be applied in an analogous manner to retirement of capacity where a market has surplus capacity. If there is surplus capacity then market prices will have a low or zero capacity component and result in operating margins below the fixed operating costs for some existing capacity. For those units where prices do not cover operating costs, units will be retired or mothballed and surplus capacity in the market will be reduced. With less surplus capacity, market prices will tend to increase and move to equilibrium levels.

The analytical process to project long-term prices and at the same time determine the amount of capacity in a market can be represented by three "price bands." The highest price band occurs in periods of deficit capacity promotes construction of new capacity; the lowest band exists when there is surplus capacity and promotes retirement of existing capacity; and the middle band exists in equilibrium and neither results in construction or retirement of capacity.

**Definition of Physical and Economic Capacity and Capacity Prices**

Prior to describing details of how long-term pricing models can be constructed in alternative capacity pricing structures, a definition of capacity must be established from an economic perspective. From a purely physical perspective, capacity is simply the maximum amount of electricity that a plant can produce at an instant. Defining capacity from an economic perspective, however, is not as clear cut because in order for capacity to have economic meaning, it must have a time dimension.

The discussion below establishes the economic definition of capacity for use in long-term pricing models. First, the notion of physical capacity is contrasted with economic capacity. Next, economic capacity is defined using three alternative notions including: (1) the probability of scarcity; (2) the number of interruption hours; and (3) the probability of exercising a call option. These definitions of capacity can be translated into mathematical formulas which are subsequently used in capacity pricing models.

### Physical versus Economic Definition of Capacity

The physical definition of capacity is the amount of electric power used or produced at an instant by a power plant. Physical capacity has no time component while energy is defined as the electric power used or produced over a specified time period. In mathematical terms, energy is the area underneath the capacity "curve" where the capacity is graphed over time (capacity on the vertical axis and time on the horizontal axis). For a single power plant, capacity is the maximum amount of power the plant can produce at an instant while energy production measures the amount of time the plant operates at various fractions of its maximum capacity:

$$\text{Energy (MWH)} = \sum_{\text{operating hours}} \text{Maximum Capacity (MW)} \times \text{Utilization per Hour}$$

While the engineering definition of capacity is straightforward and distinct from the definition of energy, the "physics book" definition of capacity has limited relevance to economics. From an economic perspective, a product must have "utility" to a consumer in order to have value. Also, to have significance from a marginal cost perspective, a "product" must yield benefits to consumers and there must be a quantity that is consumed. Using the physical definition, capacity has no economic relevance because customers cannot buy something that is does not provide anything tangible. Consumer utility comes from turning lights on, watching television, operating electric motors and so forth. Each of these uses of electricity occurs over time and cannot be measured without a time dimension. This means that if the physical definition of capacity is used in models, it has no rational value, price, or marginal cost.

From an economic perspective, it is difficult to distinguish capacity from energy because the product actually used by consumers is energy -- whether energy is used for lifting a bridge for less than one hour a year, or whether a motor in a factory uses electricity for 8,760 hours a year. The economic definition of capacity must involve distinguishing the value of using energy over different time periods. The economic definition necessary for establishing capacity prices is driven by a time dimension. This economic definition is a more complex definition than the physical definition and considers the value of insuring that energy will be available to a particular customer of for a particular use:

$$\text{Economic Capacity (MWH)} = \text{Physical Capacity (MW)} \times \text{Hours in Defined Period}$$

The amount of economic capacity depends on how energy is classified into different time periods. Time periods can be classified into periods when capacity is fully utilized and when it is not fully utilized. The value of capacity was described as the cost of depriving power to customers. The cost of depriving power or the value of that capacity can be evaluated by considering the demand characteristics that determine the value or utility of electricity during the time periods that define capacity. The next sections consider three different ways to come up with time periods that can be used to classify certain energy as capacity from an economic perspective.

### Economic Capacity Defined by the Probability of Scarcity

From an economic standpoint, capacity can be defined as the amount of energy that is sold during time periods existing capacity is fully utilized. When capacity is fully utilized, a capacity constraint exists. In practice capacity constraints are periods during a year when the total amount and/or quality of demand cannot be met with existing capacity. Examples of shortages include blackouts, voltage reductions and curtailment of interruptible load. In discussing pricing during capacity constraints, the term value of lost load and value of capacity is used interchangeably.

To value of energy during capacity constrained periods one must measure how much customers are willing to pay to insure that they are in the group that continues to receive energy. For instance, if there is only one hour in a year when capacity is fully utilized, the premium paid by customers to assure they will be able to use power in that hour is the value of capacity. In this example, the quantity of capacity is based on the time periods when a shortage occurs as shown in the formula below:

Economic Capacity (MWH) = Physical Capacity (MW) x Hours of Constraint

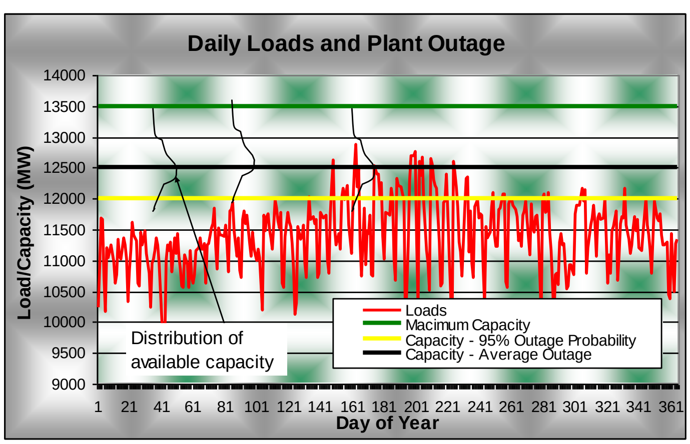
The amount of capacity in the above formula can also be defined using the concept of loss of load probability. Loss of load probability is the probability of a capacity constraint or the number of hours of capacity constraint divided by the total hours. The capacity constraint and loss of load probability depends on the maintenance outages of generating plants on the system – if there are more maintenance outages, there is less capacity and it is more likely that the capacity that is available cannot meet load. Accounting for maintenance outages with loss of load criteria, the definition of economic capacity using loss of load probability becomes:

Economic Capacity (MWH) = Physical Capacity (MW) x $LOLP_{hour}$ x 8,760

Capacity defined using the loss of load probability definition is illustrated in the graph below using daily loads and a distribution of possible available capacity. The top flat line represents physical capacity assuming no plant outages. The middle flat line represents the total capacity minus an average level of capacity and the bottom flat line represents the amount of capacity with a high confidence level. The graph demonstrates that loss of load probability – the chance that available capacity will be fully utilized -- depends on the load level, the capacity level and the outage characteristics of plants. In each day – even in days with low load levels – there is some chance that very many plants will not operate.

**Capacity Constraints and the California Meltdown**

The California meltdown illustrates examples of capacity constraints. Three types of emergency are defined. A stage 1 emergency is when reserves fall below 7%; a stage 2 emergency is when reserves fall below 5%; and, a stage 3 emergency is when reserves fall below 1.5%. In a stage 1 emergency voluntary conservation is requested; in a stage 2 emergency interruptible customers are cut; and, in a state 3 emergency, there are voluntary blackouts. There were 55 stage 1 emergencies; there were 36 stage emergencies and there was 1 stage 1 emergency during the California Meltdown in the year 2000.



### Economic Capacity Defined by Expected Interruption Hours

A second economic definition of capacity is derived from the number of hours in a year that interruptible customers experience interruptions. This definition is similar to the first definition except that information from interruptible rates rather than loss of load probability is used to measure the amount and the value of capacity. In situations where interruptible rates exist and where some customers do not opt for interruptible rates, the fact that some customers are paying more for firm power implies that they are valuing the right to be in the group that can use energy when there is not enough energy to serve all customers. If we knew the hours during which customers could be interrupted, these hours could be used to define the amount of capacity. Additionally, the price or value of the capacity is the amount customers pay in rates in order to not be in the group that is interrupted.

The decision made by a customer to become an interruptible customer involves an assessment of the difference between firm and interruptible rates which is known ahead of time and the number of interrupted hours that is not known with certainty. If the savings from the interruptible rate exceed the lost value in interrupted hours, the interruptible rate is selected. This means the capacity definition involves expected rather than actual hours of interruption. A formula for capacity quantity and capacity value using the "interruptible" definition is illustrated below:

Capacity (MWH) = Physical Capacity (MW) x Expected Hours of Interruption

and,

Value of Capacity/MWH = (Price over year for Firm – Interruptible Power) /
Expected Hours of Interruption for the Year

or, where

Probability of Interruption = Expected Interruptible Hours/8,760

then,

Capacity Price/MWH = Excess Price for Firm Power x Probability of Interruption

### Economic Capacity as the Probability of Exercising Call Option

A third economic definition of capacity uses the notion that an option on electric power can be structured to assure provide value to limit the exposure that arise when capacity is short. The basic definition of an option is the right -- but not the obligation -- to buy something in the future at a price fixed today. In terms of electricity, a call option to purchase energy can be envisioned where the holder of the option can exercise at a strike price equal to the cost of operating the last increment of capacity on a system that can physically meet load (i.e. the strike price is the energy cost of the highest cost existing unit in the market). Using the option definition, the value of capacity is the call premium the holder of an option pays for the right to receive energy at the strike price. The quantity of capacity for a customer purchasing a call option is the probability of exercising the call option. The following mathematical formulas describe economic meaning of capacity from the perspective of a call option:

Capacity Amount (MWH) = Physical Capacity (MW) x Probability of Exercise

where the probability of exercise is derived from the value of the call premium,

Call Premium/MWH = Value of Payoff/MWH when Exercised x Probability of Exercise

or, when the strike price (the cost of energy on the margin) is included:

Call Premium/MWH = Value of Payoff/MWH x Probability of Exercise – Strike Price x Probability of Exercise

The final formula is analogous to the Black-Scholes option pricing model -- the Black-Scholes formula defines the probability of exercise and the value of exercise from assumptions with respect to volatility and the distribution of prices. If capacity options were actually traded where the strike price is the cost of the last unit to dispatch, the pricing of the options could be used to measure capacity prices.

**Evaluation of Alternative Capacity Market Frameworks**

From a public policy standpoint, evaluation of alternative capacity pricing structures involves assessing the costs incurred by customers for electricity including the costs of lost load, the volatility of customer prices, the efficacy of the market in attracting new capacity, the ability of suppliers to exercise market power and many other considerations. The process of evaluating the relative merits of different capacity pricing systems begins by assessing how close the models come to optimum efficiency outcomes assuming no market power. Once deviation from the optimum is measured, issues such as market power and attraction of financial capital can be assessed.

The total cost of a system aggregates fuel costs, variable operation and maintenance cost, capital recovery cost and the cost incurred when load is not met. The latter item is measured by the value of lost load incurred by customers multiplied by the amount of lost load. Capacity cost can be measured as the aggregate physical capacity on a system multiplied by the carrying charge. In computing aggregate costs, average cost data rather than the marginal costs are compiled. The computation of total costs is analogous to revenue requirement formulas used in regulated systems. Computation of total costs is useful in the assessment of many issues such as assessment of renewable resources, measurement of customer impacts from a change in fuel prices and assessment of the effects of merging systems.

The reason for measuring total customer costs including the value of lost load can be demonstrated by considering the how to assess the energy-only market as compared to the capacity uplift market. Consider an hour in which there is a capacity constraint and not all of the demand can be supplied from existing capacity. The cost of the lost load to customer is measured by their demand elasticity and lost opportunity from not being able to use electricity no matter what is the level of the administered price. The formula for computing the total cost of the system is demonstrated by the formula below where the term “Market VOLL” is the customer cost per MWH of lost load:

| |
|---|
| Total Cost = Fuel Cost + Variable O&M Cost + Value of Lost Load + Fixed O&M Cost + Capital Recovery |

where,

| | |
|---|---|
| Fuel Cost | = Average Fuel Cost/MWH x System Generation (MWH) |
| Variable O&M | = Average Variable O&M/MWH x System Generation (MWH) |
| Fixed O&M | = Average Fixed O&M/MW x Aggregate Capacity (MW) |
| Value of Lost Load | = Market VOLL/MWH x Energy Not Served (MWH) |
| Capital Recovery | = Capital Recovery Charge (%) x Aggregate Capacity (MW) |

The alternative models can be evaluated by measuring the prices paid by customers as well as by the total cost. In comparing models which have a capacity price measured in $/MW/Year with capacity measured in $/MWH, the following simple reconciling formula can be used:

Capacity Price/MW = Capacity Value/MWH x Hours of Un-served Energy

Once the capacity price is defined in these terms, the capacity value can be spread across hours to compute the long-run equilibrium price. For example, if a customer uses the same energy in each hour of the year, the long-run equilibrium price is computed as follows:

Price/MWH = Capacity Value/MW/8760 + All-hours Energy Price/MWH

In comparing the results of alternative models, the model where capacity prices are set from customer value of lost load should result in the lowest cost. This case has no constraints and all variables are derived from market assumptions. The fact that this case has lowest cost does not mean that an energy-only market is optimal. Problems with the ability to exercise market power during high price periods and the difficulty in attracting capital for peaking plants may limit the practical aspects of the energy-only market system.

The principal modelling technique added in the energy-only model is that the level of demand is intersected with supply using an extended supply curve. The general process of moving from hour to hour with different levels of demand now is not limited to times at which there is sufficient supply tom meet the demand level. When capacity is fully utilized, prices are determined by the intersection of the portion of the curve driven by the value of lost load for customers. This approach results in a model of price spikes and un-served energy that occurs when demand exceeds the last increment of capacity. Further, the price spike level depends on the amount by which demand exceeds the existing capacity. If new supply is added in the region, the price spike will be less because the steep portion of the supply curve will not occur until the demand is at a higher level.

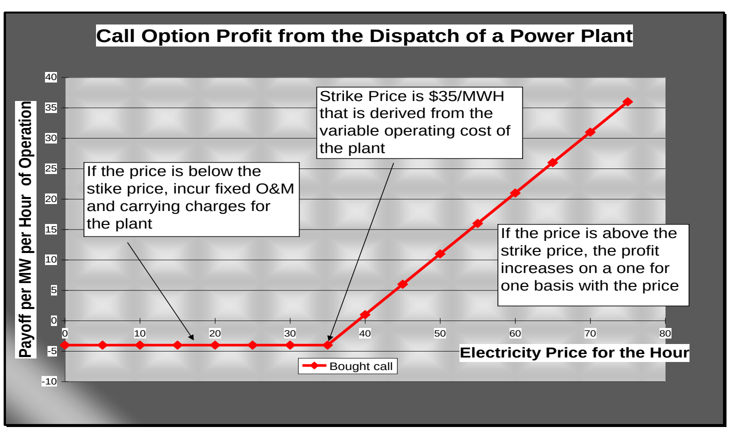
# APPENDIX 5: RISK HEDGING AND ANALYSIS OF MERCHANT POWER PLANTS

**Risk Hedging**

Importance of forward markets in future merchant markets.

Significant advances in analytical tools used to quantify and manage risk have accompanied the dramatic increases in the volume of traded derivatives for equity and debt securities markets, foreign exchange markets, fixed income markets and the markets for commodities other than electricity. Mathematical option pricing models, the most famous of which is the Black-Scholes model, have been developed and refined in the last twenty years to value a wide variety of futures, options and other derivative products. These analytical models are now central not only for many trading strategies but also to asset valuation. The risk management tools developed for financial securities can be used to moderate risk and attract capital to merchant plants. The modelling techniques for valuing derivatives can be used to value the myriad of options and contracts that are explicit or implicit in generating plants. Applications of analytical tools range from measuring the value of peaking capacity to evaluating the exposure a utility company experiences from being the provider of last resort.

The statement that operation of a power plant is analogous to an option has become a common axiom in the electric generating industry. However, the details of option pricing contracts can significantly affect their value and if power plants can be represented as option contracts, the terms of that option must be defined. Contractual terms of an option include: (1) the strike price, (2) the length of time over which the option can be exercised, (3) the manner in which the instrument will be delivered if the holder decides to exercise the option and (4) definition of how the option can be exercised during the duration of the option.




The strike price of the dispatch option is the variable operating cost of the plant. The length of time until expiration can vary from an hour to the life of the plant, but can be objectively defined depending on the valuation analysis.